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Part IV

Environmental Protection Agency

Standards of Performance for New Stationary Sources for Electric Utility Steam Generating Units; Decision in Response to Petitions for Reconsideration

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1404-6]

Standards of Performance for New Stationary Sources; Electric Utility Steam Generating Units; Decision in Response to Petitions for Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Denial of Petitions for Reconsideration of Final Regulations.

SUMMARY: The Environmental Defense Fund, Kansas City Power and Light Company, Sierra Club, Sierra Pacific Power Company and Idaho Power Company, State of California Air Resources Board, and Utility Air Regulatory Group submitted petitions for reconsideration of the revised new source performance standards for electric utility steam generating units that were promulgated on June 11, 1979 (44 FR 33580). The petitions were evaluated collectively since the petitioners raised several overlapping issues. When viewed collectively, the petitioners sought reconsideration of the standards of performance for sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x). In denying the petitions, the Administrator found that the petitioners had failed to satisfy the statutory requirements of section 307(d)(7)(B) of the Clean Air Act. That is, the petitioners failed to demonstrate either (1) that it was impractical to raise their objections during the period for public comment or (2) that the basis of their objection arose after the close of the period for public comment and the objection was of central relevance to the outcome of the rule. This notice also responds to certain procedural issues raised by the Environmental Defense Fund (EDF). It should be noted that the Natural Resources Defense Council (NRDC) filed a July 9, 1979, letter in which they concurred with the procedural issues raised by EDF.

DATES: Effective February 6, 1980.

Interested persons may advise the Agency of any technical errors by March 7, 1980.

ADDRESSES: EPA invites information from interested persons. This information should be sent to: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

Docket Number OAQPS-78-1 contains all supporting materials used by EPA in developing the standards, including public comments and materials pertaining to the petitions for reconsideration. The docket is available for public inspection and copying between 9:00 a.m. and 4:00 p.m., Monday through Friday at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Background

On September 19, 1978, pursuant to Section 111 of the Clean Air Act Amendments of 1977, EPA proposed revised standards of performance to limit emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x) from new, modified, and reconstructed electric utility steam generating units (43 FR 42154). A public hearing was held on December 12 and 13, 1978. In addition, on December 8, 1978, EPA published additional information on the proposed rule (43 FR 57834). In this notice, the Administrator set forth the preliminary results of the Agency's analysis of the environmental, economic, and energy impacts associated with several alternative standards. This analysis was also presented at the public hearing on the proposed standards. The public comment period was extended until January 15, 1979, to allow for comments on this information.

After the Agency had carefully evaluated the more than 600 comment letters and related documents, the Administrator signed the final standards on June 1, 1979. In turn, they were promulgated in the **Federal Register** on June 11, 1979.

On June 1, 1979, the Sierra Club filed a petition for judicial review of the standards with the United States Court of Appeals for the District of Columbia. Additional petitions were filed by Appalachian Power Company, et al., the Environmental Defense Fund, and the State of California Air Resources Board before the close of the filing period on August 10, 1979.

In addition, pursuant to section 307(d)(7)(B) of the Clean Air Act, the Environmental Defense Fund, Kansas City Power and Light Company, Sierra Club, Sierra Pacific Power Company and Idaho Power Company, State of California Air Resources Board, and Utility Air Regulatory Group petitioned the Administrator for reconsideration of the revised standards.

Section 307(d)(7)(B) of the Act provides that:

> Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States Court of Appeals for the appropriate circuit (as provided in subsection (b)).

The Administrator's findings and responses to the issues raised by the petitioners are presented in this notice.

Summary of Standards

Applicability

The standards apply to electric utility steam generating units capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel, for which construction is commenced after September 18, 1978. Industrial cogeneration facilities that sell less than 25 MW of electricity, or less than one-third of their potential electrical output capacity, are not covered. For electric utility combined cycle gas turbines, applicability of the standards is determined on the basis of the fossil-fuel fired to the steam generator exclusive of the heat input and electrical power contribution of the gas turbine.

SO_2 Standards

The SO_2 standards are as follows:

(1) Solid and solid-derived fuels (except solid solvent refined coal): SO_2 emissions to the atmosphere are limited to 520 ng/J (1.20 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required at all times except when emissions to the atmosphere are less than 260 ng/J (0.60 lb/million Btu) heat input. When SO_2 emissions are less than 260 ng/J (0.60 lb/million Btu) heat input, a 70 percent reduction in potential emissions is required. Compliance with the emission

limit and percent reduction requirements is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average. The percent reduction is computed on the basis of overall SO_2 removed by all types of SO_2 and sulfur removal technology, including flue gas desulfurization (FGD) systems and fuel pretreatment systems (such as coal cleaning, coal gasification, and coal liquefaction). Sulfur removed by a coal pulverizer or in bottom ash and fly ash may be included in the computation.

(2) Gaseous and liquid fuels not derived from solid fuels: SO_2 emissions into the atmosphere are limiteed to 340 ng/J (0.80 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required. The percent reduction requirement does not apply if SO_2 emissions into the atmosphere are less than 86 ng/J (0.20 lb/million Btu) heat input. Compliance with the SO_2 emission limitation and percent reduction is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.

(3) Anthracite coal: Electric utility steam generating units firing anthracite coal alone are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit on a 30-day rolling average, and all other provisions of the regulations including the particulate matter and NO_x standards.

(4) Noncontinental areas: Electric utility steam generating units located in noncontinental areas (State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Marina Islands) are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the applicable SO_2 emission limitation and all other provisions of the regulations including the particulate matter and NO_x standards.

(5) Resource recovery facilities: Resource recovery facilities which incorporate electric utility steam generating units that fire less than 25 percent fossil-fuel on a quarterly (90-day) heat input basis are not subject to the percentage reduction requirements but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit. Compliance with the emission limit is determined on a continuous basis using continuous monitoring to obtain a 30-day rolling average. In addition, such facilities must monitor and report their heat input by fuel type.

(6) Solid solvent refined coal: Electric utility steam generating units firing solid solvent refined coal (SRC I) are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit (30-day rolling average) and all requirements under the NO_x and particulate matter standards. Compliance with the emission limit is determined on a continuous basis using a continuous monitor to obtain a 30-day rolling average. The percentage reduction requirement, which is obtained at the refining facility itself, is 85 percent reduction in potential SO_2 emissions on a 24-hour (daily) averaging basis. Compliance is to be determined by Method 19. Initial full-scale demonstration facilities may be granted a commercial demonstration permit establishing a requirement of 80 percent reduction in potential emissions on a 24-hour (daily) basis.

Particulate Matter Standards

The particulate matter standard limits emissions to 13 ng/J (0.03 lb/million Btu) heat input. The opacity standard limits the opacity of emissions to 20 percent (6-minute average). The standards are based on the performance of a well-designed and operated baghouse or electrostatic precipitator.

NO_x Standards

The NO_x standards are based on combustion modification and vary according to the fuel type. The standards are:

(1) 86 ng/J (0.20 lb-million Btu) heat input from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J (0.30 lb/million Btu) heat input from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J (0.50 lb/million Btu) heat input from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;

(4) 340 ng/J (0.80 lb/million Btu) heat input from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;

(5) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from the NO_x standards and monitoring requirements; and

(6) 260 ng/J (0.60 lb/million Btu) heat input from the combustion of anthracite coal, bituminous coal, or any other solid fuel not specified under (3), (4), or (5).

Continuous compliance with the NO_x standards is required, based on a 30-day rolling average. Also, percent reductions in uncontrolled NO_x emission levels are required. The percent reductions are not controlling, however, and compliance with the NO_x emission limits will assure compliance with the percent reduction requirements.

Emerging Technologies

The standards include provisions which allow the Administrator to grant commercial demonstration permits to allow less stringent requirements for the initial full-scale demonstration plants of certain technologies. The standards include the following provisions:

(1) Facilities using SRC I are subject to an emission limitation of 520 ng/J (1.20 lb/million Btu) heat input, based on a 30-day rolling average, and an emission reduction requirement of 85 percent, based on a 24-hour average. However, the percentage reduction allowed under a commercial demonstration permit for the initial full-scale demonstration plant using SRC I would be 80 percent (based on a 24-hour average). The plant producing the SRC I would monitor to ensure that the required percentage reduction (24-hour average) is achieved and the power plant using the SRC I would monitor to ensure that the 520 ng/J heat input limit (30-day rolling average) is achieved.

(2) Facilities using fluidized bed combustion (FBC) or coal liquefaction would be subject to the emission limitation and percentage reduction requirement of the SO_2 standard and to the particulate matter and NO_x standards. However, the reduction in potential SO_2 emissions allowed under a commercial demonstration permit for the initial full-scale demonstration plants using FBC would be 85 percent (based on a 30-day rolling average). The NO_x emission limitation allowed under a commercial demonstration permit for the initial full-scale demonstration plants using coal liquefaction would be 300 ng/J (0.70 lb/million Btu) heat input, based on a 30-day rolling average.

(3) No more than 15,000 MW equivalent electrical capacity would be allotted for the purpose of commercial demonstration permits. The capacity will be allocated as follows:

Technology	Pollutant	Equivalent electrical capacity MW
Solid solvent-refined coal	SO_2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO_2	400–3,000
Fluidized bed combustion (pressurized)	SO_2	400–1,200
Coal liquefaction	NO_x	750–10,000

Compliance Provisions

Continuous compliance with the SO_2 and NO_x standards is required and is to be determined with continuous emission monitors. Reference methods or other approved procedures must be used to supplement the emission data when the

continuous emission monitors malfunction in order to provide emission data for at least 18 hours of each day for at least 22 days out of any 30 consecutive days of boiler operation.

A malfunctioning FGD system may be bypassed under emergency conditions. Compliance with the particulate standard is determined through performance tests. Continuous monitors are required to measure and record the opacity of emissions. The continuous opacity data will be used to identify excess emissions to ensure that the particulate matter control system is being properly operated and maintained.

Issues Raised in the Petitions for Reconsideration

I. SO_2 Maximum Emission Limitation of 520 ng/J (1.2 lb/Million Btu) Heat Input

The Environmental Defense Fund (EDF), Sierra Club, and State of California Air Resources Board (CARB) requested that a proceeding be convened to reconsider the maximum SO_2 emission limitation of 520 ng/J (1.2 lb/million Btu) heat input. In their petition, EDF set forth several procedural questions as the basis for their request. First, they maintained that they did not have the opportunity to comment on certain information which was submitted to EPA by the National Coal Association at an April 5, 1979, meeting and in subsequent correspondence. The information pertained to the impacts that different emission limitations will have on coal production in the Midwest and Northern Appalachia. They argued that this information materially influenced the Administrator's final decision. Further, they maintained that the Administrator's decision in setting the emission limitation was based on *ex parte* communications and improper congressional pressure.

The Sierra Club also raised objections to information developed during the post-comment period. They cited the information supplied by the National Coal Association, and the EPA staff analysis of the impact that different emission limitations would have on burnable coal reserves. In addition, they challenged the assumption that conservatism in utility perceptions of scrubber performance could create a significant disincentive against the burning of high-sulfur coal reserves. The Sierra Club maintained that this information is of "central relevance" since it formed the basis of the establishment of the final emission limitation and that the Sierra Club was denied the opportunity to comment on this information. Finally, the Sierra Club and CARB subscribed fully to arguments presented by EDF concerning ex parte communications.

Background

The potential impact that the emission limitation may have on high-sulfur coal reserves did not arise for the first time in the post-comment period. It was an issue throughout the rulemaking. In the proposal, the Agency stated that two factors had to be taken into consideration when selecting the emission limitation—FGD efficiency and the impact of the emission limitation on high-sulfur coal reserves (43 FR 42160, middle column). The proposal also indicated that, in effect, scrubber performance determines the maximum sulfur content of coals that can be fired in compliance with emission limitation even when coal preparation is employed. From the discussion it is clear that the Administrator recognized that midwestern high-sulfur coal reserves could be severely impacted if the emission limitation was not selected with care (43 FR 42160, middle column). In addition, the Administrator also specifically sought comment on the related question of new coal production as it pertained to consideration of coal impacts in the final decision (43 FR 42155, right column).

At the December 1978 public hearing on the proposed standards, the Agency specifically sought to solicit information on the impact that lower SO_2 emission limits (below 520 ng/J (1.2 lb/million Btu) heat input) would have on high-sulfur coal reserves. In response to questions from an EPA panel member and the audience, Mr. Hoff Stauffer of ICF, Inc. (an EPA consultant) testified that the potential impact of lower emission limitations on high-sulfur coal reserves would be greater in certain states than was indicated by the results of the macroeconomic analysis conducted by his firm. He added further that if the degree of reduction achievable through coal preparation or scrubbers changed from the values assumed in the analysis (35 percent for coal preparation on high-sulfur coal and 90 percent for scrubbers) the coal impacts would vary accordingly. That is, if greater reduction could be achieved by either coal preparation or by scrubbers the impacts would be reduced. Conversely, if the degree of reduction achievable by either coal preparation or scrubbers was less than the values assumed, the impacts would be more severe (public hearing transcript, December 12, 1978, pages 46–47).

The subject was broached again when Mr. Richard Ayres, representing the Natural Resources Defense Council and serving as introductory spokesperson for other public health and environmental organizations, was asked by the panel what effect lowering the emission limitation would have on local high-sulfur coal reserves. Mr. Ayres responded that a lower emission limitation may have the effect of requiring certain coals to be scrubbed more than required by the standard. He added that the utilities would have an economic choice of either buying local high-sulfur coal and scrubbing more or buying lower-sulfur coal which may not be local and scrubbing less. He further indicated that it was not clear that a lower limitation would have the effect of precluding any coal. In doing so, he noted that the "conclusion depended entirely on assumptions about the possible emission efficiencies of scrubbers." Finally, Mr. Ayres was asked whether as long as production in a given region increased that the requirement of the Act to maximize the use of local coal was satisfied. He responded that it was a "matter of degree" and that he would not say as long as production in a given region did not decline the statute was served (public hearing transcript, December 12, 1978, pages 77–80).

Mr. Robert Rauch, representing the Environmental Defense Fund, also recognized in his testimony that lowering the emission limitation to the level recommended by EDF (340 ng/J (0.8 lb/million Btu) heat input) would adversely impact high-sulfur coal reserves. In his testimony he stated "Adoption of the proposed lower ceiling would result in the exclusion of certain high-sulfur coal reserves from use in power plants subject to the revised standard." He added that the use of adipic acid and other slurry additives would enhance scrubber performance, thereby alleviating the impacts on high-sulfur coal (public hearing transcript, December 13, 1978, pages 189–191).

Mr. Joseph Mullan of the National Coal Association testified in response to a question from the hearing panel that lowering the emission limitation from 520 ng/J (1.2 lb/million Btu) heat input would preclude the use of certain high-sulfur coals. He added that the National Coal Association would furnish data on such impacts (public hearing transcript, December 13, 1978, page 246).

Turning now to the written comments on the proposed standard submitted jointly by the Natural Resources Defense Council and the Environmental Defense Fund, we see that they carefully assessed the potential impacts on high-sulfur coal reserves that could result

from various emission limitations. They concluded, "Generally, the higher the percent removal requirement, the smaller the percentage of coal reserves which are effectively eliminated for use by utility generating units." They went on to argue that if their recommended standard of 95 percent reduction in potential SO_2 emission was accepted a lower emission limitation could be adopted without adverse impacts on coal reserves (OAQPS–78–1, IV–D–631, page V–128).

Rationale for the Maximum Emission Limit

The testimony presented at the public hearing and the written comments served to confirm the Agency's initial position that scrubber performance and potential impacts on high-sulfur coal reserves had to be carefully considered when establishing the emission limitation. Meanwhile, it became apparent that the analysis performed by EPA's consultant on emission limits below 520 ng/J (1.2 lb/million Btu) heat input might not fully reflect the impacts on major high-sulfur coal production areas. This finding was evident by study of the consultant's report (OAQPS–78–1, IV–A–5, Appendix D) which showed that the model used to estimate coal production in Appalachia and the Midwest was relatively insensitive to broad variations in the emission ceiling. The Agency then concluded that the macroeconomic model was adequate for assessing national impacts on coal use, but lacked the specificity to assess potential dislocations in specific coal production regions. In effect the analysis tended to mask the impacts in specific coal producing regions through aggregation. Concern was also raised as to the validity of the modeling assumption that a 35 percent reduction in potential SO_2 emissions can be achieved by coal washing on all high-sulfur coal reserves.

In view of these concerns, EPA concluded shortly after the close of the comment period that additional analysis was needed to support the final emission limitation. In February, EPA began analyzing the impacts of alternative emission limits on local high-sulfur coal reserves. To account for actual and perceived efficiencies of scrubbers, the staff assumed three levels of scrubber control—85 percent, 90 percent, and 95 percent. In addition, two levels of physical coal cleaning were reflected. The first level was crushing to 1.5 inch top-size and the second was crushing to ⅜ inch top-size, both followed by wet beneficiation. In addition, by using seam-by-seam data on coal reserves and their sulfur reduction potential (developed for EPA's Office of Research and Development) it was possible to estimate the sulfur content of the final product coal based on reported chemical properties of coals in the reserve base (OAQPS–78–1, IV–E–12). Since this approach did not require the staff to assume a single level of sulfur reduction for all coal preparation plants, it introduced a major refinement to the analysis previously performed by EPA's consultant. The analysis was substantially completed in March 1979 (OAQPS–78–1, IV–B–57 and IV–B–72).

The April 5, 1979, meeting was called to discuss coal reserve data and the degree of sulfur removal achievable with physical coal cleaning (OAQPS–78–1, IV–E–10). The meeting gave EPA the opportunity to present the results of its analysis and to verify the data and assumptions used with those persons who are most knowledgeable on coal production and coal preparation. EPA sought broad representation at the meeting. Invitees including not only the National Coal Association but representatives from the Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, Utility Air Regulatory Group, United Mine Workers of America, and other interested parties. The invitees were furnished copies of the materials presented at the meeting, subsequent correspondence from the National Coal Association, and minutes of the meeting.

The meeting served to confirm that the coal reserve and preparation data developed independently by the EPA staff were in close agreement with those prepared by the National Coal Association (NCA). In addition, the discussion led EPA to conclude that coal preparation technology which required crushing to ⅜-inch top-size would be unduly expensive, lead to unacceptable energy losses, and pose coal handling problems (OAQPS–78–1, IV–E–11). As a result, the Administrator revised his assessment of state-of-art coal cleaning technology (44 FR 33596, left column).

In an April 19, 1979, letter to the Administrator (OAQPS–78–1, IV–D–763), attorneys for the Environmental Defense Fund and the Natural Resources Defense Council submitted comments on the information presented by the National Coal Association at the April 5, 1979, meeting and in a subsequent NCA letter to the Administrator dated April 6, 1979. In their comments, they were critical of the National Coal Association's assumptions concerning scrubber performance and the removal efficiencies of coal preparation plants. They also noted that the Associaton's data was based on a small survey of the total coal reserves in the Midwest and Northern Appalachia. They argued further that coal blending could serve to reduce the adverse impact on high-sulfur coal caused by a lower emission limit. In doing so, they recognized that the application of coal blending would have to be undertaken on a case-by-case basis. Finally, they maintained that there is no evidence that the coal industry would be unable to meet increases in coal demand even if the National Coal Association's reserve data on coal preclusions were accepted. In conclusion, they noted that the Association's data was of questionable relevance since it was predicated on a maximum removal efficiency of 90 percent.

Subsequent correspondence from the National Coal Association served to reaffirm a point that had been made earlier in the rulemaking. That is, utilities would have a choice of either buying lower-sulfur coal and scrubbing to meet the percent removal requirement or buying higher-sulfur coal and scrubbing more than required by the standard in order to meet the emission limitation. In addition, they cited the conservative nature of utilities and stressed that this would be reflected in their coal buying practices. As was discussed at the public hearing and in the written comments such behavior by utilities would result in adverse impacts on the use of certain local high-sulfur coals.

In reaching final conclusions about the impact of the SO_2 standard on coal production, the Administrator judged that utilities would be inclined to select coals that would meet the emission limit with no more than 90 percent reduction in potential SO_2 emissions [1] (44 FR 33596, left column). With this assumption, the analysis revealed that an emission limit of less than 520 ng/J (1.20 lb/million Btu) heat input would create a disincentive to burn a significant portion of the coal reserves in the Midwest and Northern Appalachia (OAQPS–78–1, IV–B–72). If the emission limit had been set at 430 ng/J (1.0 lb/million Btu) heat input, 15 percent of the total reserve base in the Eastern Midwest (Illinois, Indiana, and Western Kentucky) would have been impacted. The impact in Northern Appalachia would be 6 percent and this impact would have been concentrated in the areas of Ohio and the northern part of West Virginia. If only currently

[1] The previous version of the EPA analysis had assumed either 85 or 90 percent control levels in addition to coal washing. That approach disregarded the fact that the net reduction in potential SO_2 emissions may have been greater than 90 percent in some cases.

owned coal reserves are considered, up to 19 percent of the high-sulfur coals in some regions would be impacted (OAQPS–78–1, IV–B–72). The Administrator judged that such impacts are unacceptable.

The final point made by NCA was that utility coal buying practice typically incorporates a margin of safety to ensure compliance with SO_2 emission limitations. Rather than purchasing a high-sulfur coal that would barely comply with the emission limit, the prudent utility would adopt a more conservative approach and purchase coal that would meet the emission limit with a margin of safety in order to account for uncertainty in coal sulfur variability. This approach, which reflects sound engineering principles, could result in the dislocation of some high-sulfur coal reserves.

The Administrator determined that consideration of a margin of safety in coal buying practice was reasonable. Using NCA's recommendation of an 8.5 percent margin (reported as "about 10 percent" in the preamble to promulgation), coal impacts were reanalyzed. This study showed additional coal market dislocations (OAQPS–78–1, IV–B–72). For example, in Illinois, Indiana, and Western Kentucky, the impact on coal reserves by a 430 ng/J (1.0 lb/million Btu) heat input emission limit increased from 15 percent without the margin to 22 percent when the margin was assumed. Considering only currently owned reserves, the impact increased from 19 percent to 30 percent. Even with the margin, the analysis predicted no significant impact for a 520 ng/J (1.2 lb/million Btu) heat input standard.

Having determined the extent of the potential coal impacts associated with a lower emission limit, the Agency then assessed the potential environmental benefits. The assessment revealed that by 1995 an emission limit of 430 ng/J (1.0 lb/million Btu) heat input would reduce national emissions by only 50 thousand tons per year relative to the 520 ng/J (1.2 lb/million Btu) heat input limit. That is, the projected emissions from new plants would be reduced from 3.10 million tons to a 3.05 million tons as a result of the more stringent emission limit (OAQPS–78–1, IV–B–75).

The petitions providing no information to either refute the assumptions or the findings of the final coal impact analysis. The Sierra Club argued that EPA had misinterpreted its own analysis of coal impacts (Sierra Club petition, page 9). They maintained that the EPA figures presented at the April 5 meeting (OAQPS–78–1, IV–E–11, attachment 3) supported establishment of a 340 ng/J (0.8 lb/million Btu) heat input standard. In doing so the Sierra Club ignored the analysis performed by the Agency after the April 5 meeting, particularly with respect to the Administrator finding that utilities would purchase coal which would meet the emission limit (with margin) with no more than 90 percent reduction in potential SO_2 emissions.

In conclusion, the decision as to the appropriate level of emission limitation rested squarely on two factors. First, the Administrator's finding that a 90 percent reduction in potential SO_2 emissions, measured as a 30-day rolling average, represented the emission reduction achievable through the use of the best demonstrated system of emission reduction, and second, that the marginal environmental benefit of a 430 ng/J (1.0 lb/million Btu) heat input standard coupled with a 90 percent reduction in potential SO_2 emissions could not be justified in light of the potential impacts on high-sulfur coal reserves. If he had determined, as some petitioners suggested, that higher removal efficiencies were achievable on high-sulfur coals, the emission limitation could have been established at a lower level without significant impacts on local high-sulfur coal reserves.

Environmental Defense Fund Procedural Issues

EDF's petition objected to the fact that after the close of the public comment period, representatives of the National Coal Association and a number of members of Congress talked to EPA officials and submitted documents to EPA arguing that the ceiling should be set at 520 ng/J (1.2. lbs/million Btu) heat input. EDF objected to these communications on a number of grounds. First, they argued that it was improper, under Section 307(d) of the Act, for the Agency to consider information submitted more than 30 days after the public hearing. Second, they objected that the Agency failed to make transcripts of the oral communications, and that, in any event, the summaries of those communications that the Agency placed in the docket were inadequate. Third, they implied that Agency officials received additional oral communications which were not documented in the rulemaking docket. Fourth, they objected that these written and oral communications were *ex parte* and therefore improper, citing, for example, *United States Lines, Inc.* v. *FMC,* 584 F. 2d 519 (D.C. Cir., 1978). Fifth, they argued that the Administrator's decision on the ceiling was based in part on information obtained in *ex parte* discussions and thus not placed in the docket as of the date of promulgation, in violation of Section 307(d). Finally, they argued that the communications from members of Congress constituted improper pressure on the Administrator's decision, citing, for example, *D.C. Federation of Civic Associations* v. *Volpe,* 459 F. 2d 1231 (D.C. Cir. 1972). EDF argued that these alleged procedural errors were of central relevance to the outcome of the rule, and that the Agency should therefore convene a proceeding to reconsider.

The Administrator does not believe that the procedures cited by EDF were improper. Moreover, as discussed below, any arguable errors were not of central relevance to the outcome of the rule, and therefore do not constitute grounds for granting EDF's petition to reconsider.

First, it was not improper for the Administrator to consider information submitted more than 30 days after the public hearing. Section 307(d)(5) requires that the Administrator consider documents submitted up to 30 days after the hearing. It does not forbid the Administrator to consider additional comments submitted after that 30-day period.

Second, the Agency's summaries of oral communications were adequate. Section 307(d)(5) does not require, as EDF argues, that Agency officials keep transcripts of their oral discussions with persons outside the Agency. It simply requires the Agency to make a transcript of the public hearing on a proposed rulemaking. Third, Agency officials wrote memoranda of all significant oral communcations between Agency officials and persons outside the executive branch, such as the two meetings with Senator Byrd, and the memoranda were promptly placed in the rulemaking docket. These memoranda accurately reflect the information and arguments communicated to the Agency.

Fourth, the oral and written communications cited by EDF were not *ex parte.* The Agency promptly placed the written comments in the rulemaking docket where they were available to the public. Also, the NCA sent copies of its written comments directly to the principal parties to the rulemaking, including EDF and NRDC. Similarly, the Agency placed the memoranda of oral communcations in the docket where they were available to the public. Any member of the public has had the opportunity to submit a petition for reconsideration if that information was used erroneously by EPA in setting the standard, and several persons have done so.

Fifth, contrary to EDF's assertion, the Administrator's decision on the

emission ceiling was not based on any information not in the docket.

Finally, it was not improper for the Administrator to listen to and consider the views of Senators and Congressmen, including Senator Byrd. It is not unusual for members of Congress to express their views on the merits of Agency rulemaking, and it is entirely proper for the Administrator to consider those views.

EDF objects particularly to a meeting the Administrator attended with Senator Byrd on April 26, 1979, arguing that the contact was *ex parte* and improperly influenced the Administrator's decision. Neither contention is correct. A memorandum summarizing the discussion at the meeting was placed in the docket, and members of the public have had the opportunity to comment on it, as EDF has done. No new information was presented to the Administrator at the meeting.

Senator Byrd's comments at this meeting also did not improperly influence the Administrator. Although the Senator strongly urged the Administrator to set the emission ceiling at a level that would not preclude the use of any significant coal reserves, the Administrator had already concluded from the 1977 Amendments to the Clean Air Act that the revised standards should not preclude significant reserves. This view was based on the Administrator's interpretation of the legislative intent of the 1977 Amendments and was reflected in the proposed emission ceiling of 520 ng/J (1.2 lbs/million Btu) heat input, as discussed in the preamble to the proposed standards (43 FR 42160).

This view was reaffirmed in the final rulemaking, based on the intent of the 1977 Amendments (44 FR 33595–33596). Although the Administrator was aware (as he would have been even in the absence of a meeting) of Senator Byrd's concern that a ceiling lower then 520 ng/J (1.2 lbs/million Btu) heat input would inappropriately preclude significant coal reserves, the Administrator's decision was not based on Senator Byrd's expression of concern. The Administrator had already concluded that anything more than a minimal preclusion of the use of particular coal reserves would, in the absence of significant resulting emission reductions, be inconsistent with the intent of the 1977 Amendments. Because the Agency's analysis showed that even an emission limit of 430 ng/J (1.0 lbs/million Btu) heat input could preclude the use of up to 22 percent of certain coal reserves without significantly reducing overall emissions, the Administrator's judgment was that a ceiling lower than 520 ng/J (1.2 lbs/million Btu) heat input was not justified. Thus, the views of Senator Byrd and other members of Congress, at most, served to reinforce the Administrator's own judgment that the proper level for the standard was 520 ng/J (1.2 lbs/million Btu) heat input. Even assuming, therefore, that it was improper for the Administrator to consider the views of members of Congress, this procedural "error" was not of central relevance to the outcome of the rule.

II. SO_2 Minimum Control Level (70 Percent Reduction of Potential Emissions)

The Kansas City Power and Light Company (KCPL), Sierra Club, and Utility Air Regulatory Group (UARG) requested that a proceeding be convened to reconsider the 70 percent minimum control level which is applicable when burning low-sulfur coals. Both the Sierra Club and UARG maintained that they did not have an opportunity to fully comment on either the final regulatory analysis or dry SO_2 scrubbing technology since the phase 3 macroeconomic analysis of the standard (44 FR 33603, left column) and supporting data were entered into the record after the close of the public comment period. Both claimed that their evaluation of this additional information provided insights which are of central relevance to the Administrator's final decision and that reconsideration of the standard is warranted. The KCPL petition did not allege improper administrative procedures, but asked for reconsideration based on their evaluation of the merits of the standard.

In seeking a more stringent minimum reduction requirement, the Sierra Club contended that dry SO_2 scrubbing is not a demonstrated technology and, therefore, no basis exists for a variable control standard. Alternatively, the Sierra Club maintained that if dry technology is considered demonstrated the record supports a more stringent minimum control level. With respect to the regulatory analysis, the petition charged that faulty analytical methodology and assumptions led the Agency to erroneous conclusions about the impacts of the promulgated standard relative to the more stringent uniform or full control alternative. They suggested that analysis performed using proper assumptions would support adoption of a uniform standard.

In support of a less stringent minimum reduction requirement, the UARG petition presented a regulatory analysis which was prepared by their consultant, National Economic Research Associates (NERA). Based on this study, UARG argued that a 50 percent minimum requirement would be superior in terms of emissions, costs, and energy impacts. Finally, they argued that a lower percent reduction would provide greater opportunity to develop dry SO_2 scrubbing technology.

In their petition KCPL sought either an elimination of the percent reduction requirement when emissions are 520 ng/J (1.2 lb/million Btu) heat input or less, or, as an alternative, a reduction in the 70 percent requirement. In support of their request, KCPL set forth several arguments. First, they cited the economic and energy impacts associated with the application of scrubbing technology on low sulfur coals. Second, they noted that a significant portion of sulfur in the coal they plan to burn will be removed in the fly ash. Finally, they asserted that health and welfare considerations do not warrant scrubbing of low sulfur coals since their uncontrolled SO_2 emissions are less than the emissions allowed by the standard for high-sulfur coals with 90 percent scrubbing.

The primary basis for the UARG and Sierra Club requests for reconsideration of the minimum control level was the Agency's phase 3 economic modeling analysis (44 FR 33602). Because the phase 3 analysis was completed after the close of the public comment period, it is important that the results of that study are viewed in proper perspective to their role in the Administrator's decision. The petitioners implied that the adoption of the 70 percent variable control standard was based solely on the phase 3 analysis and that the phase 3 analysis was a new venture by the Agency, and therefore, the public was excluded from active participation in the decision process. This notion is false.

Contrary to views of the UARG and the Sierra Club, the phase 3 study did not mark a significant departure from the Agency's earlier analysis of the issue of uniform versus variable control. No new economic modeling concepts were introduced nor were any modeling input assumptions changed from those presented in the phase 2 analysis. Instead, the phase 3 study served merely (a) to refine the analysis by incorporating consideration of dry SO_2 scrubbing in response to public comments and (b) to facilitate specification of the final standard. In effect, phase 3 brought together the results of an analysis that had proceeded under close public scrutiny for more than a year. In order to consider the full range of applicability of dry SO_2 scrubbing systems, it was necessary to introduce a new alternative standard—the variable control standard

with a 70 percent minimum control level. Introduction of this option was considered appropriate since it raised the same kind of economic, legal, and technical policy issues as the earlier analyses of 33, 50, and 90 percent minimum control options.

Within this context, many of the objections to the economic modeling are inappropriate grounds under section 307(d)(7)(B) for reconsideration since they do not involve information on which it was impracticable to comment during the public comment period. For example, the Sierra Club's comments regarding modeling assumptions merely restated those that had been incorporated by reference into their January 1979 comments (OAQPS–78–1, IV–D–631 and IV–D–626). The only new modeling issue raised during phase 3 was the application and cost of dry SO_2 scrubbing. These problems notwithstanding each of the issues raised by the various petitions were evaluated carefully and are discussed below.

Dry Scrubbing Technology

The Sierra Club and UARG both raised issues concerning dry SO_2 scrubbing technology in their petitions for reconsideration. While UARG concurred with EPA's basic approach with respect to dry scrubbing, they maintained that the Agency's objective of developing the full potential of this technology would be better served by a 50 percent minimum reduction requirement. On the other hand, the Sierra Club was most critical of EPA's consideration of dry scrubbing in the rulemaking. They maintained that the public was not afforded sufficient opportunity to comment on dry scrubbing technology. They argued that EPA had not identified dry scrubbing as a demonstrated technology nor had the Agency set forth any regulatory options that embraced the technology. They also asserted that the treatment of dry scrubbing in the rulemaking was inconsistent with Agency actions concerning other emerging technologies such as the establishment of commercial demonstration permits for solvent refined coal and fluidized bed combustion, and the rejection of catalytic ammonia injection for NO_x control on the grounds that it had not been employed on a full-scale facility. They also maintained that EPA had shown little interest in dry scrubbing prior to the spring of 1979 and seized upon it only after the need arose to justify a 70 percent minimum reduction requirement. Finally, the Sierra Club asserted that even if one assumed dry scrubbing is adequately demonstrated, the 70 percent reduction requirement is too low. In doing so, they cited information (Sierra Club petition, page 8) in the record that indicated that "up to 90 percent reduction" can be achieved with such systems.

A review of the public record belies these charges. The preamble to the proposed standards identified dry SO_2 scrubbing, including spray drying, as an alternative to wet FGD systems (43 FR 42160, left column). Subsequently, a number of individuals and organizations either submitted written comment or presented testimony at the public hearing in support of a variable control standard since it would not foreclose the development of dry SO_2 control technology. For example, the spokesman for the Public Service Company of Colorado (PSCC) testified that his firm was actively pursuing dry SO_2 control technology (dry injection of sodium-based reagents upstream of a baghouse) because it offered a number of advantages compared to wet technology. Advantages included lower energy consumption, fewer maintenance problems, and simplified waste disposal (public hearing transcript, December 13, 1978, pages 92–94). When questioned by the hearing panel, PSCC testified that 70 percent removal is achievable with dry scrubbing and that they would pursue the technology if a 70 percent requirement was adopted (public hearing transcript, December 13, 1978, page 102). Similarly, Northern States Power testified that adoption of a sliding scale would give impetus to their examination of dry SO_2 control systems which employ a spray absorber and a fabric filter (public hearing transcript, December 13, 1978, page 226). Finally, the Department of Public Utilities, City of Colorado Springs testified that they have a program to conduct on-site pilot tests of a spray-drying system for SO_2 control. It was also noted that if a sliding scale approach was adopted "we feel there is no question but that dry techniques would be used" (public hearing transcript, December 13, 1978, pages 266–267).

The Air Pollution Control Commission, Colorado Department of Health urged in their written comments that the proposed emission floor be raised to 172 ng/J (0.40 lb/million Btu) heat input in order to permit the development and application of dry control techniques such as the injection of dry absorbants into a baghouse. They noted that their recommendation would require approximately 65 percent reduction on a typical western low-sulfur coal (OAQPS–78–1, IV–D–212). The Washington Public Power Supply System also submitted written comments that affirmed the Agency's finding on dry scrubbers as set forth in the proposal. They indicated that dry scrubbing was superior to wet technology when applied to western low-sulfur coal. They noted that the application of dry scrubbers would result in lower capital, fuel, and operation and maintenance costs, as well as lower water use and simplified waste disposal. They indicated further that the uncertainty of being able to achieve the proposed 85 percent reduction requirement would foreclose the installation of dry scrubbing technology. Therefore, they recommended that the proposed emission floor be raised to at least 210 ng/J (0.5 lb/million Btu) heat input (OAQPS–78–1, IV–D–330).

Because of these comments and the public hearing testimony, the Agency carried out additional investigations of dry scrubbing technology during the post-comment period. The findings of the analysis (44 FR 33582 and EPA 450/3–79–021, page 3–61) confirmed the views of the commenters that the adoption of a uniform percentage reduction requirement would have constrained the development of dry scrubbing technology. After carefully reviewing the available pilot plant data and information on the three full-scale units that are under construction, it was the Administrator's judgment that the technology employing spray dryers could achieve 70 percent reduction in potential SO_2 emissions on both low-sulfur alkaline and nonalkaline coals. Data on higher emission reduction levels such as those noted by the Sierra Club were discounted since they reflected short-term removal efficiencies (not representative of longer periods of performance) and they were achieved when high-alkaline content coals were fired. The Administrator's judgment was also tempered in this regard by the public comments which indicated that removal requirements higher than 70 percent would discourage the continued development of the technology. Similarly, these same commenters clearly indicated that the technology was capable of exceeding the 50 percent reduction requirement suggested by the Utility Air Regulatory Group.

The Sierra Club commented that EPA was inconsistent in its treatment of dry scrubbing and catalytic ammonia injection. In rejecting catalytic ammonia injection for NO_x control, the Administrator noted that it had not been adequately demonstrated. A review of the record reveals that the primary proponent of this technology, the State

of California Air Resources Board, also recognized that it was not sufficiently advanced at this time to be considered. Instead, they merely recommended that the standard require plants to set aside space so that catalytic ammonia injection could be added at some future date (OAQPS–78–1, IV–D–268). In comparison, dry scrubbing has undergone extensive testing at pilot plants, and there are three full-scale facilities under construction that will begin operation in the 1981–82 period.

With respect to commercial demonstration permits for solvent refined coal and fluidized bed combustion, the standard merely allows initial, full-scale demonstration units some flexibility. Subsequent commercial facilities will be required to meet the final standards. In adopting this provision, the Administrator recognized that initial full-scale demonstration units often do not perform to design specification, and therefore some flexibility was required if these capital intensive, front-end technologies were to be pursued. On the other hand, the Agency concluded that more conventional devices such as dry scrubbers could be scaled up to commercial-sized facilities with reasonable assurance that the initial facilities would comply with the applicable requirements. In view of this, the inclusion of dry scrubbing under the commercial demonstration permit provision was not appropriate.

Finally, in a letter dated September 17, 1979, to the Administrator, the Sierra Club submitted additional information to buttress its argument that dry scrubbing is not demonstrated technology. This letter cited EPA's "FGD quarterly Report" of Spring 1979. The report indicates that the direct injection of dry absorbents (such as nahcolite) into the gas stream may be a breakthrough, yet it calls for further pilot plant studies. The inference the Sierra Club drew from the article was that the EPA technical staff does not believe dry scrubbing is sufficiently developed to be considered in the rulemaking. The Sierra Club failed to recognize that there are several different dry scrubbing approaches in different stages of development. The "FGD Quarterly Report" does not pertain to the approach employing a spray dryer and baghouse with lime absorbent which serves as the basis for the Administrator's finding (EPA–450/3–70–021 at 3–61).

The Sierra Club also cited an article in the Summer 1979 "FGD Quarterly Report" on vendors' perspectives toward dry scrubbing. In doing so, the Sierra Club noted that the article indicates that vendors expressed an attitude of caution toward dry scrubbing which led the Sierra Club to conclude that the technology is not available. It should be noted from the article that only one of the vendors present was actively engaged in dry scrubbing and that firm was quite positive in their remarks. Babcock and Wilcox, who had conducted spray dryer pilot plant studies and is pursuing contracts for full-scale installations, commented that "while the dry scrubbing approach is new, the technology is proven."

Economic Modeling

The Agency's regulatory analysis concluded that the variable control standard with a 70 percent minimum control level would result in equal or lower national sulfur dioxide emissions than the uniform 90 percent standard while having less impact on costs, waste disposal, and oil consumption (44 FR 33607, middle column and 33608). The Sierra Club petition charged that the Agency used an unrealistic model and faulty assumptions in reaching these conclusions. The petition alleged that utility behavior as predicted by the EPA model is "incredible" and that this incredible behavior leads to "the outlandish notion that stricter emission controls will lead to more emissions." The Administrator finds this allegation to be without merit.

The principle modeling concept being challenged is whether or not increased costs of constructing and operating a new plant (due to increased pollution control costs) will affect the utility operator's decisions on boiler retirement schedules, the dispatching of plants to meet electrical demand, and the rate of construction of new plants. The model used for the analysis assumed that utility companies over the long term will make decisions that minimize the cost of electricity generation. That is, (1) under any demand situation utilities will first operate their equipment with the lowest operating costs, and (2) existing generating capacity will be replaced only if its operating costs exceed the capital and operating costs of new equipment. While political, financial, or institutional constraints may bar cost-minimizing behavior in individual cases, the Administrator continues to believe that the assumption of such behavior is the most sound method of analyzing the impacts of alternative standards.

Under this approach, the model simultaneously adjusts both the utilization of existing plants and the construction schedule of new plants (subject to Subpart Da) based on the relative economics of generating electricity under alternative standards. Hence, average capacity factors for the population of new plants may vary among standards due to variations in the mix of base and intermediate loaded plants which are brought on line in any one year. But this does not mean, as concluded in the Sierra Club petition at page 8, that the model predicted that utilities would permit new base-loaded units to remain idle while they continue to build still more new units.

The petition also alleged that this modeling concept was introduced in the phase 3 analysis, which was completed after the close of the public comment period, and hence the modeling rationale was not subject to public review. The petition went on to criticize some of the assumptions in the model charging that they were not even mentioned in the record.

The Administrator finds no basis for the Sierra Club's assertion that the modeling methodology and input assumptions were not exposed for public review. First, the same model was used for the phase 1, 2, and 3 analyses. The basic model logic was explained in the preamble to the September proposal and comments were solicited specifically on the use of a cost optimization model for simulating utility decisions (43 FR 42162, left column).

Secondly, the model's input assumptions were subjected to broad review. Assumptions were presented in the September preamble and in even greater detail in the consultant's reports which are part of the record (OAQPS–78–1, II–A–42, II–A–90, and II–A–91). Following proposal, the Agency convened an interagency working group to review the macroeconomic model and the Agency's input assumptions (44 FR 33604, left column). Members of the group represented a spectrum of expertise and interests (energy, employment, environment, inflation, commerce). The group met numerous times over a period of two months, including meetings with UARG, NRDC, and Sierra Club. As a result of the group's recommendations, the phase 2 analysis was conducted. A full description of the analysis including changes to the modeling assumptions was presented at the public hearing and a detailed report was put into the record (OAQPS–78–1, IV–A–5). For the phase 3 analysis accompanying promulgation, the only change in modeling assumptions from phase 2 was the introduction of dry scrubbing technology. Based on the detailed record established, the Administrator concludes that the Sierra Club had ample opportunity to analyze and

comment on the Agency's analytical approach and did so by incorporating the EDF and NRDC comments into their January 1979 comments (OAQPS–78–1, IV–D–626).

The Sierra Club also criticized the conclusions of the Agency's regulatory analysis because the assumed oil prices were too low and the nuclear plant growth rate was too high. To assist in evaluating the petitions, two sensitivity tests were performed on the Agency's regulatory analysis. Using the phase 3 assumptions as a base, the analysis was rerun first assuming higher oil prices and then assuming both higher oil prices and a lower nuclear growth rate (OAQPS–78–1, VI–B–16). The studies addressed the promulgated standard, the full control option (uniform 90 percent control), and a variable control standard with a 50 percent minimum control requirement as recommended by UARG. The predictions for 1995 are summarized in Tables 2 and 3, respectively. For comparison, the phase 3 results are repeated in Table 1.

With respect to energy input assumptions, the oil prices used by the Agency for the phase 3 analysis were based on the Department of Energy's estimate of future crude oil prices. These estimates are now probably low because of the 1979 OPEC price increase which occurred after promulgation of the standard. For the sensitivity analysis, the following oil prices in 1979 dollars were assumed:

Assumed Oil Prices

[Dollars per Barrel]

	Sensitivity analysis	Phase 3
1985	25	16
1990	30	20
1995	38	26

These prices were obtained from conversations with DOE's policy analysis staff. The prices may appear low in comparison to the example of $41.00 per barrel spot market oil given in the Sierra Club petition, but the Sierra Club figure is misleading because utilities seldom purchase spot market oil. The meaningful parameter is the average refiners' acquisition cost, which was $21/barrel at the time of this analysis. The original nuclear capacity assumptions were based on the industry's announced plans for new capacity. For sensitivity testing, these estimates were modified by excluding nuclear power plants in the early planning stages while retaining those now under construction or for which, based on permit status, plans appear firm. The following assumptions of total nuclear capacity resulted:

Table 1.—*Summary of 1995 Impacts With Phase 3 Assumptions* [1]

	Level of control with 520 ng/J maximum emission limit			
	Current standards	Variable control, 50 pct minimum	Variable control, 70 pct minimum	Full control
National SO_2 Emissions (million tons)	23.8	20.6	20.5	20.7
East [2]	11.2	9.7	9.7	10.1
Midwest	8.3	8.0	8.0	7.9
West South Central	2.6	1.8	1.7	1.7
West	1.7	1.1	1.1	0.9
Incremental Annualized Cost (billions 1978 $)		2.9	3.3	4.4
Incremental Cost of SO_2 Reduction (1978 $/ton)		914	1,036	1,428
Oil Consumption (million bbl/day)	1.4	1.6	1.6	1.8
Coal Production (million tons)	1,767	1,745	1,752	1,761
Total Coal Capacity (GW)	554	537	537	520

[1] With wet and dry scrubbing and the following energy assumptions:

	Oil prices ($ 1975)	Nuclear Capacity (GW)
Year:		
1985	$12.90	97
1990	16.40	165
1995	21.00	228

[2] See 44 FR 33608 for designation of census regions.

Table 2.—*Summary of 1995 Impacts With Higher Oil Prices*[1]

	Level of control with 520 ng/J maximum emission limit			
	Current standards	Variable control, 50 pct minimum	Variable control, 70 pct minimum	Full control
National SO_2 Emissions (million tons)	23.2	19.8	19.6	19.7
East [2]	10.9	9.1	9.1	9.5
Midwest	[illegible]	7.9	7.8	7.8
West South Central	2.6	1.7	1.6	1.5
West	1.6	1.1	1.0	0.9
Incremental Annualized Cost (billions 1978 $)		3.3	3.6	5.0
Incremental Cost of SO_2 Reduction (1978 $/ton)		[illegible]	977	1,049
Oil Consumption (million bbl/day)	0.9	0.9	0.9	0.9
Coal Production (million tons)	1,800	1,797	1,802	1,832
Total Coal Capacity (GW)	[illegible]	[illegible]	[illegible]	[illegible]

[1] With wet and dry scrubbing and the following energy assumptions:

	Oil prices ($ 1975)	Nuclear capacity (GW)
Year:		
1985	$20.20	97
1990	24.20	165
1995	30.70	228

[2] See 44 FR 33608 for designation of census regions.

Table 3.—*Summary of 1995 Impacts With Higher Oil Prices and Less Nuclear Growth*[1]

	Level of control with 520 ng/J maximum emission limit			
	Current standards	Variable control, 50 pct minimum	Variable control, 70 pct minimum	Full control
National SO_2 Emissions (million tons)	25.0	20.9	20.6	20.5
East [2]	12.0	[illegible]	9.7	10.1
Midwest	8.6	[illegible]	8.1	[illegible]
West South Central	8.6	1.8	1.7	1.6
West	1.7	1.2	1.1	0.9
Incremental Annualized Cost (billions 1978 $)		3.8	4.1	5.9
Incremental Cost of SO_2 Reduction (1978 $/ton)		[illegible]	914	1,259
Oil Consumption (million bbl/day)	0.9	0.9	0.9	0.9
Coal Production (million tons)	1,940	1,943	1,946	1,984
Total Coal Capacity (GW)	644	644	644	643

[1] With wet and dry scrubbing and the following energy assumptions:

	Oil prices ($ 1975)	Nuclear Capacity (GW)
Year:		
1985	$20.20	[illegible]
1990	24.20	141
1995	30.70	173

[2] See 44 FR 33608 for designation of census regions.

Assumed Nuclear Capacity

	Sensitivity analysis	Phase 3
1985	92 GW	97 GW
1990	141 GW	165 GW
1995	173 GW	228 GW

Environmentally, the impact of higher oil prices was to reduce SO_2 emissions (Table 2). For example, under the promulgated standard (hereafter referred to as "the standard") national SO_2 emissions in 1995 were projected to drop from 20.5 million tons predicted in phase 3 (44 FR 33608) to 19.6 million tons. This reduction occurred because the higher oil prices led to the retirement of about 50 gigawatts (GW) of existing oil-fired capacity. While these retirements increased the demand for new coal-fired plants, new plants (subject to Subpart Da) on average were less polluting than the oil-fired capacity they replaced. Therefore, the net effect of oil replacement on a broad regional basis was to reduce SO_2 emissions.

The relative impacts of the alternative standards under the sensitivity tests remained about the same. Sulfur dioxide emissions under the standard were still predicted to be lower than with either full control or the 50 percent variable standard. The emissions benefit relative to full control was reduced from 200,000 tons per year to 100,000 tons per year. Regionally, the effect of the higher oil prices on the relative impacts of the standards was mixed. In comparison to full control, the standard continued to reduce emissions in the East by 400,000 tons per year, but resulted in an additional 70,000 tons in the West and 100,000 tons in the West South Central (relative to phase 3). However, as pointed out above, emissions in all regions were less than or equal to those under the phase 3 oil price assumptions.

The cost of all the standards increased under the higher oil price assumption. This increase was due to the cost of additional coal capacity and corresponding emission control equipment. Relative to the standard, the cost of full control increased by $300 million per year over the $1.1 billion difference predicted under lower oil prices.

At the higher oil prices, 1995 oil consumption by utilities was predicted to be the same under all standards tested. Depending on the standard, consumption was 500,000 to 800,000 barrels per day lower than under the phase 3 projections with lower prices. The reason that the environmental standards had no effect on oil consumption was that at the assumed rate of oil price increase, all base- and intermediate-loaded oil capacity was retired by 1995 and the only remaining oil use was in combustion turbines used to meet peak demand.

Under the assumption of both high oil prices and slowed nuclear growth (Table 3), national and regional SO_2 emissions were predicted to be about the same as under the phase 3 projections. This effect was due to the counterbalancing emission impacts. As noted above, higher oil prices resulted in a net decrease in SO_2 emissions. But at the same time the reduced supply of nuclear generation capacity precipitated demand for an additional 55 GW of new coal capacity beyond that required under the projection with high oil prices. On a national level the emissions from these new coal-fired plants offset the emission reductions achieved by the oil replacements.

With this additional 55 GW of new coal-fired capacity, the environmental impact of alternative standards was more significant. Baseline emission projections (i.e., assuming no change to the original standard) increased from 23.8 million tons per year under the phase 3 energy assumptions to 25.0 million tons per year. Accordingly, the promulgated standard reduced national SO_2 emissions in 1995 by almost 4.5

million tons per year in contrast to about 3.5 million tons per year under both the phase 3 and the high oil price sensitivity projections.

While emission levels were roughly the same as under the phase 3 energy assumptions, the relative impacts of the alternative standards changed somewhat. National emissions were predicted to be 100,000 tons less under full control than under the standard. Relative to full control, the standard was still predicted to reduce emissions by about 400,000 tons in the East, but on a national basis this was offset by emission increases in the other regions. With higher oil prices and less nuclear capacity, the environmental benefit of full control in the West and West South Central was greater by about 100,000 tons, but this impact is masked in Table 3 due to rounding. The variable standard with a 50 percent minimum control level resulted in about 400,000 tons per year more emissions than full control and about 300,000 tons per year more than the standard.

The total cost of all the alternatives increased due to the increased coal capacity. Relative to the standard, the cost of the 50 percent variable control standard remained about the same. The full control standard, however, was significantly more expensive. The marginal cost of full control (relative to the standard) increased from $1.1 billion under the phase 3 energy assumptions to $1.8 billion.

Energy impacts were about the same as those predicted in the high oil price sensitivity runs. Oil consumption was still predicted at about 900,000 barrels per day under all alternative standards. Coal production under all alternatives increased by about 100 million tons per year.

Even considering the uncertainty of future oil prices and nuclear capacity, the Administrator found no basis for convening a proceeding on the modeling issue. The sensitivity runs did not show significant changes in the relative impacts of the alternatives. Under the sensitivity test with both high oil prices and slowed nuclear growth, full control for the first time showed lower emissions nationally than the standard. But the cost of this additional 100,000 tons of control was estimated at $1.8 billion, which represents more than a 40 percent increase in the incremental cost of the standad (Table 3). The principal environmental benefit of full control would be felt in the West and West South Central. Through case-by-case new source review ample authority exists to require more stringent controls as necessary to protect our pristine areas and national parks (44 FR 33584, left column). As a result, the Administrator continues to believe that the flexibility offered by the standard will lead to the best balance of energy, environmental, and economic impacts than either a uniform 90 percent standard or a 50 percent variable standard and hence better satisfies the purposes of the Act.

On the other side of the modeling issue, UARG charged that the Agency's regulatory analysis does not support a 70 percent minimum requirement. The petition called the Agency's control cost estimates unrealistic and presented a macroeconomic analysis which concluded that a 50 percent minimum requirement would result in a more favorable balance of cost, energy, and environmental impacts.

Response to the UARG petition was difficult because the UARG position was presented in two separate reports submitted at different times, and the two reports reached different conclusions. In the formal petition, UARG recommended 50 percent minimum control and promised a detailed report by NERA supporting their position. When the NERA report arrived six weeks later, it recommended 30 percent control. In light of this confusion, it was decided to review each report separately based on its own merits, but devote primary attention to the 50 percent recommendation. After reviewing UARG's macroeconomic analysis, the Administrator finds no convincing arguments for altering the conclusion that the 70 percent minimum removal requirement provides the best balance of impacts. In the formal petition, UARG's conclusion that a 50 percent standard is superior was based on a NERA economic analysis which assumed that only wet scrubbing technology was available to utilities. A detailed analysis of the NERA results was not possible because only summary outputs were supplied in their comments. But the results of this analysis seem to coincide with the Agency's conclusions that there are energy, environmental, and economic benefits, associated with standards that provide a lower cost control alternative for lower sulfur coals. The problem with the UARG initial analysis is that it overlooked the economic benefits of dry scrubbing.

In recognition of this shortcoming, UARG presented their estimate of the costs of dry scrubbing made by Battelle Columbus Laboratories (UARG petition, page 25) and then hypothesized without supporting analysis that "with realistic cost assumptions the advantages of a lower percent removal are likely to increase even further" (UARG petition, page 27). Table 4 compares Battelle's costs to those used in the EPA regulatory analysis. The two estimates are almost the same. More importantly, the two estimates agree that the cost of a 70 percent efficient dry system is not significantly greater than the cost of a 50 percent efficient system, and this conclusion had important implications in the specification of the standard. Based on these comparisons, the Administrator finds that the UARG petition supports the Agency's dry scrubbing cost assumptions and the finding that no significant cost benefit will result from a standard with a 50 percent minimum control level.

Table 4.—*Comparison of UARG and EPA dry SO_2 Scrubbing Costs* [1] *(Mills/kwh)*

Percent removal	Inlet sulfur (lbs SO_2/million Btu)	UARG	EPA
50	0.80	[2] 1.68	2.06
	2.00	[2] 2.13	2.44
70	0.80	1.97	2.66
	2.00	2.54	2.66

[1] Wet scrubbing costs range up to 6 mills/kwh.
[2] UARG costs based on 55 percent removal.

In their second report, UARG presented additional economic analyses by NERA. In those analyes, the impacts of 30, 50, and 70 percent minimum control standards were tested assuming that both wet and dry scrubbing technology were available. The analyses were performed with three different sets of control cost assumptions—EPA's costs, Battelle's costs, and an additional set of costs specified by NERA. The report concluded that the 70 percent standard is superior using EPA's costs but that under the other cost estimates the 30 percent standard is better. The cost effectiveness of alternative standards (dollars per ton of pollutant removed) was their principal basis of evaluation. UARG then alleged that EPA overestimated the differences in cost between wet and dry scrubbing and that this error led to the wrong conclusion about the impacts of the 70 percent minimum removal requirement. The EPA cost assumptions were criticized primarily because different methods were used to estimate dry and wet scrubbing costs. To justify their position, UARG presented estimates of wet and dry scrubbing costs developed by Battelle. UARG believes that Battelle understand scrubber costs, but that Battelle's relationship between wet and dry scrubbing costs is more accurate than EPA's (UARG petition, page 7). As noted above, Battelle agreed with the Agency's dry scrubbing costs, but for

wet scrubbing the Battelle costs were substantially lower than the Agency's.

Typically, when comparing results of studies, the Agency has detailed documentation with which to compare the methods of costing and analysis. In this case, the Administrator had documentation for neither the NERA costs nor the Battelle costs. The NERA costs were unreferenced and supported by neither engineering analysis nor vendor bids. They assumed that the capital cost of a dry scrubber is 10 percent less than that for a comparable wet scrubber and that the operating costs and energy requirements are the same for the two systems. The UARG petition promised a detailed report from Battelle, but the report was not delivered. Without a basis for evaluation, the Battelle and NERA costs can only be considered as hypothetical data sets for the purpose of sensitivity testing of the economic analysis. They cannot be considered as new information on SO_2 control costs.

The EPA cost estimates, on the other hand, have withstood several critical tests. The PEDCo cost model for wet scrubbers which was used by EPA was thoroughly reviewed by Department of Energy (DOE) consultants, and DOE concurred with the EPA estimates through the interagency working group. Later, the Agency's costs were again reviewed in detail against wet scrubber costs predicted by the Tennessee Valley Authority's scrubber design model. While the two models initially seemed to produce divergent results, careful analysis of the respective costing methodology showed that for similar design specifications the two models produced costs that were very close, the major difference stemming from different assumptions about the construction contingency fee (OAQPS–78–1, IV–B–50). The Administrator concluded from these cost comparisons that the Agency's flue gas desulfurization cost assumptions are reasonable.

The EPA dry scrubbing costs were based primarily on engineering studies submitted by electric utility companies and equipment vendors for the full-scale utility systems now on order or under construction. Using these studies, the EPA cost estimates were made in full cognizance of the basic assumptions used in the PEDCo wet scrubbing model. The result was that for economic modeling purposes (OAQPS–78–1, IV–A–25, page B–17) the dry scrubbing cost estimates in the background document (EPA 450/5–79–021, page 3–67) were increased to reflect similar fuel parameters, local conditions, and degree of design conservatism as reflected in the wet scrubbing costs. Since care was taken in aligning these costs, the Administrator does not accept UARG's allegation that EPA's costs for wet and dry scrubbing are invalid because they were developed on an inconsistent basis.

Even if EPA accepted UARG's unsubstantiated cost assumptions, the NERA sensitivity analyses provided no new insights nor did they materially contradict the Agency's basic conclusions about the standard. Using the Battelle costs and NERA's "alternative scrubber costs" as a range, NERA predicted that relative to 50 percent minimum control, a 70 percent standard would reduce national SO_2 emissions by an additional 250 to 450 thousand tons per year compared to about 100 thousand tons estimated by EPA (Table 1). NERA predicted the additional costs of a 70 percent minimum standard relative to a 50 percent requirement would be between $300 million and $400 million per year compared to $300 million predicted by EPA. It was only in moving to 30 percent control that the NERA results showed a distinct cost savings ($600 to $900 million) over the 70 percent level, but the 30 percent standard produced an additional 700 thousand tons per year of SO_2 under both of their control cost scenarios. The Administrator rejects the 30 percent standard advocated by UARG because the potential cost savings do not justify the potential emission increases. In conclusion, the trade-offs between costs and emissions shown by UARG are generally similar to those predicted by EPA in promulgating the standard and therefore do not support a different standard from the 70 percent variable standard adopted.

Other Issues

Kansas City Power and Light Company sought either an elimination of the percent reduction requirement when emissions are 520 ng/J (1.2 lbs/million Btu) heat input or less or as an alternative a reduction in the 70 percent minimum control requirement. In their arguments, KCPL cited annualized control costs for wet scrubbing of $11.4 million and an energy penalty of 70 thousand tons of coal per year to operate a scrubber. Second, they noted that 14 percent of the potential SO_2 emissions from the coal they plan to burn will be removed by the fly ash. Taking these two factors in account, KCPL computed a cost effectiveness ratio for a hypothetical 650 MW unit to be $3,600 per ton of sulfur removed and concluded that such control was too expensive. Finally, they concluded that scrubbing low-sulfur coals is not warranted since uncontrolled SO_2 emissions from their new plants will be less than the emissions allowed by the standard for high-sulfur coals with 90 percent scrubbing.

After careful review, the Administrator finds that the KCPL petition provided no legal or technical basis for reconsidering the final rule. First, the question of whether a plant burning low-sulfur coal should be required to meet the same percentage reduction requirement as those burning high-sulfur coal has been a central issue throughout this decision-making. Since this issue was raised in the proposal (43 FR 42155, left column), KCPL had ample opportunity to make their points during the public comment period. In fact, it was the recognition of this trade-off in emissions between high-sulfur and low-sulfur coal that led the Administrator to first consider the concept of variable control standards (43 FR 42155, right column). While sulfur removal by fly ash does not represent best demonstrated technology for SO_2 control, sulfur removal by fuel pretreatment, fly ash, and bottom ash may be credited toward meeting the 70 percent requirement.

Second, the KCPL petition does not allege the requisite procedural error that the standard was based on information on which they had no opportunity to comment. Their objections center primarily on the economic and energy impacts of wet SO_2 scrubbing on low-sulfur coal. These issues were clearly identified by the Agency in the background document supporting proposal (OAQPS–78–1, III–B–3, Chapters 5 and 7). Furthermore, the preamble to proposal specifically requested comments on the Agency's assumptions for the regulatory analysis (43 FR 42162, left column).

Finally, and more importantly, the major points made by KCPL are not of central relevance to the outcome of the rule because the information presented does not refute the Agency's data base on wet scrubbing. Consider the following comparisons to the assumptions of the EPA regulatory analysis.

(a) The control costs quoted by KCPL for a 650 MW unit were $31 million in capital and $6.2 million in operating expenses. The EPA assumptions applied to a comparably sized unit result in $55 million in capital costs and $7 million in operating expense.

(b) KCPL quoted an energy impact of 8 tons of coal per hour to operate the scrubber. Considering their operating requirement of 460 tons of coal per hour, the energy penalty of SO_2 control is 1.7

percent. The Agency's economic model assumed 2.2 percent.

(c) KCPL computed cost effectiveness of the standard at $3600 per ton of sulfur removed. This figure is based on a misunderstanding of the application of the fly ash removal credit toward the 70 percent removal requirement. According to the standard, the scrubbing requirement when assuming a 14 percent SO_2 removal in flyash is 65 percent rather than 56 percent as calculated by KCPL. At 65 percent scrubbing, the cost per ton of sulfur removed is $3100. This converts to a cost of $1550 per ton of sulfur dioxide removed which is similar to the costs estimated by EPA for low-sulfur coal applications (OAQPS–78–1, III–B–3 and IV–B–14).

Thus, the Administrator has already concluded that energy and economic costs greater than those cited by KCPL are justified to achieve the emission reductions required by the standard.

Conclusions on Minimum Control Level

After carefully weighing the arguments by the three petitioners, the Administrator can find no new information or insights which are of central relevance to his conclusions about the benefits of a variable control standard with a 70 percent minimum removal requirement. The Sierra Club and UARG correctly point out that the Agency's phase 3 analysis was completed after the close of the public comment period and that they were therefore unable to comment on the final step of the regulatory analysis. But in assessing these comments it is important to put the phase 3 analysis in proper context with its role in the final decision. The Administrator's conclusions about the responses of the utility industry to alternative standards were not based on phase 3 alone, but a series of economic studies spanning more than a year's effort. These analyses were performed under a range of assumptions of economic conditions, regulatory options, and flue gas desulfurization parameters. The phase 3 analysis was merely a fine tuning of the regulatory analysis to reflect dry scrubbing technology.

No new modeling concepts or assumptions were introduced in phase 3. The fundamental modeling concept as introduced in the September proposal (43 FR 42161, right column) has not changed. The model input assumptions were the same as those of the phase 2 analysis presented on December 8, 1978 (44 FR 54834, middle column), and at the December 12 and 13, 1978, public hearing. Detailed consultants' reports on the modeling analyses were available for comment before the close of the public comment period. This public record provided adequate opportunity for the public to comment both on the principal concepts and detailed implementation of the regulatory analysis before the close of the public comment period.

Even though new information was added to the record after the close of the comment period, none of the petitions raised valid objections to this information or cast any uncertainty that is germane to the final decision. The Administrator has very carefully weighed the petitioners comments on dry scrubbing and the UARG sensitivity analysis on pollution control costs. Not only did the UARG analysis generally confirm the conclusions of the EPA regulatory analysis, but it established that even if dry scrubbing costs vary substantially, the relative impacts of a 50 versus 70 percent minimum removal requirement change very little. The 70 percent standard was estimated to produce lower emissions for only slightly higher costs. Differences in cost effectiveness, which UARG seem to weigh most heavily, varied by only $2 to a maximum of $50 per ton of SO_2 removed across alternative cost estimates. In the final analysis none of the petitions repudiated the Agency's findings on the state of development, range of applicability, or costs of dry SO_2 scrubbing. In light of these findings, the Administrator finds the information in the petitions not of central relevance to the final rule and therefore denies the requests to convene a proceeding to reconsider the 70 percent minimum removal requirement.

III. SO_2 Maximum Control Level (90 percent reduction of potential SO_2 emissions)

Petitions for reconsideration submitted by the Utility Air Regulatory Group (UARG) and the Sierra Club questioned the basis for the maximum control level of 90 percent reduction in potential SO_2 emissions, 30-day rolling average. The other petitions did not address this issue. However, in a July 18, 1979, letter, the Environmental Defense Fund (EDF) requested EPA to review utilization of adipic acid scrubbing additives as a basis for a more stringent maximum control level. An additional analysis by UARG was forwarded to EPA on January 28, 1980. Although it was reviewed by EPA, a detailed response could not be prepared in the three days afforded EPA for comment prior to the court's deadline of January 31, 1980, for EPA to respond to the petitions. However, the only issue not previously raised by UARG (boiler load variation) has been addressed by this response.

With their petition, UARG submitted a statistical analysis of flue gas desulfurization (FGD) system test data which purportedly revealed certain flaws in the Agency's conclusions. The UARG petition maintained that a scrubber with a geometric mean (median) efficiency of 92 percent could not achieve the standard because of variations in its performance. UARG also maintained that the highest removal efficiency standard that can be justified by the Agency's data is 85 percent, 30-day rolling average. In the alternative, they suggested that the 90 percent, 30-day rolling average standard could be retained if an adequate number of exemptions were permitted during any given 30-day averaging period. On the other hand, the Sierra Club questioned why the standard had been established at 90 percent when the Agency had documented that well-designed, operated, and maintained scrubbers could achieve a median efficiency of 92 percent. In doing so, they argued that a 90 percent, 30-day rolling average standard was not sufficiently stringent.

After reviewing their petitions, the Administrator finds that the Sierra Club and UARG overlooked several significant factors which were of critical importance to the decision to promulgate a 90 percent, 30-day rolling average standard. The Sierra Club position was based on a misunderstanding of the statistical basis for the standard. The UARG analysis was flawed because it did not consider the sulfur removed by coal washing, coal pulverizers, bottom ash, and fly ash (hereafter, collectively referred to as sulfur reduction credits). Instead the UARG petition based its conclusions on the performance of the FGD system alone. In short, UARG did not analyze the promulgated standard (44 FR 33582, center column). Furthermore, UARG underestimated the minimum performance capability of scrubbers by assuming that future scrubbers would not even achieve the level of process control demonstrated by the best existing systems tested by EPA.

EPA has prepared two reports which re-analyze the same FGD test data considered in UARG's analysis. One report identified the important design and operating differences in the FGD systems tested (OAQPS–78–1, VI–B–14) by EPA and the second report provided additional statistical analyses of these data (OAQPS–78–1, VI–B–13). The results of the EPA analyses showed that:

1. Flue gas desulfurization systems can achieve a 30-day rolling average efficiency between 88 percent and 89

percent (base loaded boilers) or between 86 and 87 percent (peak loaded boilers) with no improvements in currently demonstrated process control.

2. Even if a new FGD system attained only 85 percent efficiency (30-day rolling average), a 90 percent reduction in potential SO_2 emissions can be met when sulfur reduction credits are considered.

To clarify the basis for the Agency's conclusions, the following discussion reviews the development of information used to establish the final percent reduction standard. Initially, EPA studied the application of FGD systems for the control of SO_2 emissions from power plants. As part of that effort, information which described the status and performance of FGD systems in the U.S. and Japan was inventoried and evaluated. These evaluations included the development of design information on how to improve the median efficiency of FGD systems based upon an extensive testing program at the Shawnee facility (OAQPS–78–1, II–A–75). The Shawnee test data and other data (OAQPS–78–1, II–A–71) on existing FGD systems were generated by short-term performance tests. These data did not define the expected performance range (the minimum and maximum SO_2 percent removal) of state-of-the-art FGD systems.

Because a continuous compliance standard was under consideration, information about the process variation of FGD systems was needed to project the performance range of scrubber efficiency around the median percent removal level. For the purpose of measuring process variation, several existing FGD systems were monitored with continuous measurement instrumentation. The selection of FGD systems to be tested was limited principally to the few FGD systems available which were attaining 80 to 90 percent median reduction of high-sulfur coal emissions. When examining the results of these tests, it should be recognized that they do not reflect the performance of a new FGD system specifically designed to attain a continuous compliance standard.

When the percent reduction standard was proposed, EPA projected the performance of newly designed FGD systems. The projection, referred to as the "line of improved performance" in the analysis, was principally based on the information on how to improve median system performance (OAQPS–78–1, III–B–4). The line showed that compliance with the proposed standard (85 percent reduction in potential SO_2 emissions, 24-hour average) could be attained with an FGD system if the only improvement made relative to an existing FGD system was to increase the median efficiency to 92 percent. The "line of improved performance" did not reflect the sulfur reduction credits that could be applied towards compliance with the proposed standard or the improvements in process control (less than 0.289 geometric standard deviation) that could be designed into a new facility. While these alternatives were discussed in detail and included within the basis for the proposed standard (OAQPS–78–1, III–B–4), the purpose of the "line of improved performance" was to show that even without credits or process control improvements, the proposed standard could be met. Upon proposal, the source owner was provided a choice of complying with the percent reduction standard by (1) an FGD system *alone* (85 percent reduction, 24-hour standard), or by (2) use of sulfur reduction credits together with an FGD system attaining less than 85 percent reduction.

After proposal, EPA continued to analyze regulatory options for establishing the final percent removal requirement. On December 8, 1978, economic analyses of these additional options were published in the **Federal Register** (43 FR 57834) for public comment. In this notice EPA stated that:

> Reassessment of the assumptions made in the August analysis also revealed that the impact of the coal washing credit had not been considered in the modeling analysis. Other credits allowed by the September proposal, such as sulfur removed by the pulverizers or in bottom ash and flyash, were determined not to be significant when viewed at the national and regional levels. The coal washing credit, on the other hand, was found to have a significant effect on predicated emissions levels and, therefore, was taken into consideration in the results presented here.

This statement gave notice that the effect of the coal washing credit on emission levels for the proposed control options had not been properly assessed in previous modeling anayses. In the economic analyses completed before proposal, the environmental benefits of the proposed standard were optimistic because it was assumed that all high-sulfur coal would be washed, but a corresponding reduction in the level of scrubbing needed for compliance was not taken into account. This error resulted in the analyses understimating the amount of national and regional SO_2 emissions that would have been allowed by the proposed standard. This problem was discussed at length at the public hearing on December 12, 1978 (OAQPS–78–1, IV–F–1, p. 11, 22, 28, and 29).

UARG addressed this question of coal washing in comments submitted in response to recommendations presented at the public hearing by the Natural Resources Defense Council (OAQPS–78–1, IV–F–1, p. 65, 12–12–78) that the final standards be based upon the removal of sulfur from fuel *together with* the removal of SO_2 from flue gases with a FGD system. In their comments (OAQPS–78–1, IV–D–725, Appendix A, p. 23), UARG had three main objections:

(1) All coals are not washable to the same degree.

(2) Coal cleaning may not be economically feasible.

(3) The Clean Air Act and the Resource Conservation and Recovery Act may preclude the construction of coal washing facilities at every mine.

EPA has reviewed these comments again and does not find that they change the Administrator's conclusion that washed coal can be used in conjunction with FGD systems to attain a 90 percent reduction in potential SO_2 emissions. First, EPA realizes that all coal is not equally washable. In the regulatory analaysis, the degree of coal washing was a function of the rank and sulfur content of the coal. Moreover, because of the variable control scale inherent in the standard, 75 percent of U.S coal reserves would require less than 90 percent reduction in potential SO_2 emissions. The remaining 25 percent are high sulfur coals on which the highest degree of sulfur removal by coal washing are acheived. Second, the washing assumptions used by the Agency reflected the percentage of sulfur removal currently being attained by conventional coal washing plants in the U.S. (OAQPS–78–1, IV–D–756). These washing percentages were therefore cost-feasible assumptions because they are typical of current washing practices. Finally, the Agency does not believe that environmental regulations will prohibit the cleaning of coal. The Clean Air Act and the Resource Conservation and Recovery Act may impose certain environmental controls, but would not prevent the routine construction of coal washing plants. Thus, the Agency concluded that the basis for the promulgated standard could be a combination of FGD control and fuel credits.

Based on these findings, EPA stated (44 FR 33582) that the 90 percent reduction standard "can be achieved at the individual plant level even under the most demanding conditions through the application of flue gas desulfurization (FGD) systems together with sulfur reductions achieved by currently practiced coal preparation techniques. Reductions achieved in the fly ash and

bottom ash are also applicable". Thus, FGD systems *together with* removal of sulfur from the fuel was the basis for the final standard. The standard prohibits the emission of more than "10 percent of the potential combustion concentration (90 percent reduction)." That is, the final standard requires 90 percent reduction of the potential emissions (the theoretical emissions that would result from combustion of fuel in an uncleaned state), not 90 percent removal by a scrubber.

Since UARG failed to take into consideration sulfur reduction credits, UARG analyzed a more stringent standard than was promulgated. Furthermore, EPA's review revealed that while the statistical methodology in the UARG analysis was basically correct, it was flawed by UARG's assumption about the process variation of a new FGD system. As a result, the statistical anaysis was improperly used by UARG to project the number of violations expected by a new FGD system.

To elaborate on the variability issue, page 14 of the UARG petition states:

> The range of efficiency variability values resulting from this analysis represents the range of efficiency variabilities that can be expected to be encountered at future FGD sites.

This assumption artificially inflated the amount of variability that would reasonably be expected in a new FGD system because it presumed that there were no major design and operational differences in the existing FGD systems tested and that the performance of new systems would not improve beyond that of systems tested by EPA. To estimate process variability of new FGD systems, UARG simply averaged together all data from all systems tested including malfunctioning systems (Conesville). EPA's review of these data showed that there were major design and operating differences in the existing FGD systems tested and that the process control could be improved in new FGD systems (OAQPS–78–1, VI–B–14). Therefore, not all of the FGD systems tested by EPA were representative of best demonstrated technology for SO_2 control.

These major differences in the FGD systems tested are apparent when the test reports are examined (OAQPS–78–1, VI–B–14).One of the tests was conducted when the FGD systems were not operating properly (Conesville). Two tests were conducted on regenerative FGD systems (Philadelphia and Chicago) which are not representative of a lime or limestone FGD system. Another test was on an adipic acid/lime FGD system (Shawnee-venturi). None of these tests were representative of the process variation of well-operated, lime or limestone FGD systems on a high-sulfur coal application (OAQPS–78–1, VI–B–14).

Only three systems were tested when (1) the unit was operating normally, and (2) pH control instrumentation was in place and operational (Pittsburgh, Shawnee-TCA, and Louisville). Only at Shawnee did EPA purposely have skilled engineering and technician personnel closely monitor the operation during the test (OAQPS–78–1, VI–B–14). Data from these systems best describe the process control performance of existing lime/limestone FGD systems.

During the Pittsburgh test, there were some problems with pH meters. The data was separated into Test I (pH meter inoperative) and Test II (pH meter operative). During Test I, operators measured pH hourly with a portable instrument (OAQPS–78–1, VI–B–14). Analysis of these data show low process variation during each test period (OAQPS–78–1, VI–B–13). Although the process variation during the second test was 10 percent lower, the difference was not found to be statistically significant. Data taken during each test (I and II) are representative of control attainable with pH controls only. Boiler load was relatively stable during the test. Average process variation as described by the geometric standard deviation was 0.21 and 0.23, respectively.

At Shawnee, only pH controls were in use, but additional attention was given to controlling the process by technical personnel. Boiler load was purposely varied. Geometric standard deviation was 0.18, which was similar to that recorded at Pittsburgh. UARG acknowledged that careful attention to control of the FGD operation by skilled personnel was an important factor in control of the Shawnee-TCA scrubber process (OAQPS–78–1, II–D–440, page 3). It was at the Shawnee test that the best control of FGD process variability by an existing FGD system was demonstrated (OAQPS–78–1, II–B–13).

The Louisville test appears to represent a special case. The average process variation was significantly higher (0.30 and 0.34 for the two units tested) than was recorded at the two other tests (Pittsburgh and Shawnee). An EPA contractor identified two factors which potentially could adversely affect process control at Louisville (OAQPS–78–1, VI–B–14). First, they noted that Louisville was originally designed in the 1960's and has had significant retrofit design changes which could affect process control. Second, the degree of operator attention given to process control is unknown. In addition, UARG showed that an additional factor which may affect the FGD process control is boiler load changes. Unlike a new boiler, the Louisville unit is an older boiler which has been placed into peaking service and therefore experiences significant load changes during the course of a day. As was the case with Pittsburgh and Shawnee, Louisville only uses pH controls to regulate the process. The process variation was analyzed and the maximum process variation of the Louisville system, at a 95 percent confidence level, was determined to be 0.36 geometric standard deviation (OAQPS–78–1, VI–B–13). This estimate of process variation represents a "worst case" situation since it reflects the degree of FGD variability at a peaking unit rather than on the more easily controlled immediate- or base-loaded applications.

In addition to basing their projections on nonrepresentative systems, UARG has also ignored information in a background information document (OAQPS–78–1, II–B–4, section 4.2.6) on feasible process control improvements which were currently used in Japan (OAQPS–78–1, II–I–359). An appraisal of the degree of process instrumentation and control in use at the existing FGD systems tested and a review of the feasible process control improvements which can be designed into new FGD systems was also reviewed (OAQPS–78–1, VI–B–14). As described in this review, none of systems tested had automatic process instrumentation control in operation. All adjustments to scrubber operation were made by intermittent, manual adjustments by an operator. Automatic process controls, which provide immediate and continuous adjustments, can reduce the process control response time and the magnitude of FGD efficiency variation. Even the best controlled FGD systems tested (the Shawnee FGD system, which was designed in the 1960's) employed only feedback pH process control systems (OAQPS–78–1, IV–J–20). None of these existing FGD systems were designed with the feedforward process control features now used in Japan (OAQPS–78–1, II–I–359) for the automatic adjustment of scrubber make-up in response to changing operating conditions. These systems respond to boiler load changes or the amount of SO_2 in the flue gases to be cleaned before they impact the scrubbing system. The use of such systems would improve the control of short-term FGD efficiency variation. At the FGD systems tested, the actual flue gas SO_2

concentration (affected by coal sulfur content) and gas volume (affected by boiler load) was not routinely monitored by the FGD system operators for the purpose of controlling the FGD operation as is currently practiced in Japan (OAQPS–78–1, II–I–359). Thus, even the best controlled existing systems tested were not representative of the control of process variation that would be expected in the performance of new FGD systems to be operated in the 1980's (OAQPS–78–1, VI–B–14). For the purpose of describing the range in performance of an FGD system using only feedback pH control and which are known to have received close attention by operating personnel, the data recorded at these two existing FGD systems (Pittsburgh, test II and Shawnee-TCA) have been used by EPA to project the maximum process variation that would result (0.23 geometric standard deviation) at a 95 percent confidence interval for a base loaded boiler. The data from Louisville was used to represent performance of a peak loaded boiler (0.36 geometric standard deviation at the 95 percent confidence level). These values are conservative because the data collected at the existing FGD systems tested are not representative of the lower process variation that would be expected in future FGD systems designed with improved process control systems (OAQPS–78–1, VI–B–14).

EPA's statistical analysis of scrubber efficency is in close agreement with the UARG analysis when the same process variation and amount of autocorrelation was assumed. EPA's analysis showed about the same autocorrelation effect (the tendency for scrubber efficiency to follow the previous day's performance) as UARG's analysis. A "worst-case" 0.7 autocorrelation factor was used in both analyses even though a more favorable 0.6 factor could have been used based upon the measured autocorrelation of the data at the Shawnee-TCA and Pittsburgh tests. A comparison of the minimum 30-day average performance of a FGD system based upon EPA and UARG process variation assumptions is given in Table 5a.

The EPA analysis (OAQPS–78–1, VI–B–13) summarized in Tables 5a and 5b shows the median scrubbing efficieny required to achieve various minimum 30-day rolling average removal levels (probability of 1 violation in 10 years). The three sets of estimates shown are based on (1) the same process control demonstrated at Pittsburgh, test II and loaded, well-operated existing plant (σ_g=0.20 on average and σ_g=0.23 at the 95 percent confidence level), (2) the same process control demonstrated at Louisville which represents a peak loaded, existing plant (σ_g=0.32 on average and σ_g=0.36 at the 95 percent confidence level), and (3) the poor process control projected by UARG (σ_g=0.29 on average and σ_g=0.43 at the 95 percent confidence level). The process variation is described on a 24-hour, geometric standard deviation (σ_g) basis to allow comparison with UARG's analysis. However, the minimum FGD efficiencies shown in Tables 5a and 5b are 30-day rolling averages.

It is evident from the analysis summarized in Table 5a that if a new FGD system could be operated at least as well as the two best controlled existing FGD systems tested, a 92 percent efficient scrubber (median) can achieve between 88 and 89 percent control on a 30-day rolling average Shawnee-TCA, which represents a base basis.[1] More than 89 percent minimum reduction could be obtained if the process variations in new FGD systems are kept under better control with new control system instruments and careful attention by operating personnel. Even the peak-loaded Louisville system, which has much higher process variability (σ_g=0.32 on average), could achieve 86 to 87 percent reduction.

When reviewing the results of analyses contained in Tables 5a and 5b, it must be kept in mind that they represent "worst case" projections of compliance capability. Neither the UARG nor EPA projections took into account load shifting or the effect of a spare FGD module as a means of countering worst-case system performance (as portrayed by the 95 percent confidence level).

[1] With a risk assumption of one violation per year (the assumption used by UARG) the minimum 30-day rolling average was between 89 percent and 90 percent control at the 95 percent confidence level (OAQPS–78–1, VI–B–13, page 1–4).

Table 5a.—*Median FGD Efficiency to Attain Minimum 30-day Rolling Average Standard for Base Loaded Units*[a]

Minimum 30-day rolling average FGD efficiency	Median efficiency for existing well-controlled FGD systems tested [EPA basis]		Median efficiency for all existing FGD systems tested [UARG basis]	
	Average [σ_g=0.20]	Maximum [σ_g=0.23]	Average [σ_g=0.29]	Maximum [σ_g=0.43]
90	92.6	[illegible]	[illegible]	[illegible]
[illegible]	91.8	[illegible]	[illegible]	[illegible]
[illegible]	91.1	91.5	[illegible]	[illegible]
87	90.3	90.8	[illegible]	[illegible]
86	89.6	[illegible]	90.9	[illegible]
85	88.8	[illegible]	[illegible]	92.3

[a] Estimates are based on probability of only 1 violation in 10 years. Process variation (σ_g is expressed as one geometric standard deviation, 24-hour basis). The maximum process variation is projected at the 95th percentile.

Table 5b.—*Median FGD Efficiency to Attain Minimum 30-day Rolling Average Standard for Peak Loaded Units.*[a]

Minimum 30-day rolling average FGD efficiency	Median efficiency for peak loaded, existing FGD systems tested [EPA basis]	
	Average [σ_g=0.32]	Maximum [σ_g=0.36]
90	[illegible]	94.2
[illegible]	93.2	93.6
88	[illegible]	93.1
[illegible]	[illegible]	92.5
86	91.4	[illegible]
[illegible]	[illegible]	91.3

[a] Estimates are based on probability of only 1 violation in 10 years. Process variation (σ_g) is expressed as one geometric standard deviation, 24-hour basis. The maximum process variation is projected at the 95th percentile.

EPA also contended that an FGD system supplier could miss the mark in designing a 92 percent median efficiency FGD system and that a miscalculation of only 1 or 2 percent in median efficiency would prevent the FGD system from complying with the final SO_2 percent reduction standard (UARG petition, Appendix B, p. 64). EPA specifically addressed this miss-the-mark argument when it established a variable control standard (70 percent to 90 percent reduction). In the preamble to the final standard EPA stated, "Finally, under a variable approach, a source could move to a lower sulfur content coal to achieve compliance if its control equipment failed to meet design expectations" (44 FR 33583, left column). An FGD system designed for high-sulfur coal would increase in scrubbing efficiency if a lower-sulfur coal were fired, and the amount of removal required for compliance would drop from 90 percent to as low as 70 percent reduction in potential SO_2 emissions.

Even if, as UARG contends, an FGD system on a 30-day rolling average basis (through poor design or operating practices) could only attain 85 percent reduction, the facility would comply with the promulgated 90 percent reduction standard when credits for sulfur removed by coal washing, pulverizers, and in bottom and fly ash are considered. These credits which can

be substantial, are summarized as follows:

1. *Coal washing.* On high-sulfur midwestern coals that would be subject to the 90 percent reduction requirement, an average of 27 percent sulfur removal was achieved by conventional coal washing plants in 1978 (OAQPS–78–1, IV–D–761). Even in Ohio where the lowest average coal washing reduction was recorded, 20 percent reduction was attained. These data represent current industry practice and do not necessarily represent full application of state-of-the-art in coal cleaning technology.

2. *Coal pulverizers.* Additional sulfur reductions are also attainable with coal pulverizers used at power plants. Coal is typically pulverized at power plants prior to combustion. By selecting a specific type of coal pulverizer (one that will reject pyrites from the pulverized coal), sulfur can be removed. One utility company reported to EPA that sulfur reductions of 12% to 38% (with 24% average removal) had been obtained (OAQPS–78–1, II–D–179) by the pulvizers alone when a program had been implemented to optimize the rejection of pyrites by the pulverizer equipment.

3. *Ash retention.* One utility company has reported 0.4% to 5.1% sulfur removal credit in bottom ash alone with eastern and midwestern coals and 7.3% to 15.9% removal with a western coal (OAQPS–78–1, II–B–72). To determine how much sulfur is removed by the bottom ash and fly ash combined, EPA conducted a study in which numerous boilers were tested. The amount of SO_2 emitted was compared to the potential SO_2 emissions in the coal. For eight western coals and six midwestern coals, an average sulfur retention of 20 percent and 10 percent, respectively, was found (OAQPS–78–1, IV–A–6). Thus, an average of at least 10 percent SO_2 reduction can be attributed to sulfur retention in coal ash.

These credits *together with* an FGD system continuously achieving as little as 85 percent reduction are sufficient to attain compliance with the final SO_2 percent reduction standard as is shown in Table 6:

Table 6.—*Impact of Sulfur Reduction Credits on Required FGD Control Efficiencies to Attain 90 Percent Overall SO_2 Reduction*

SO_2 removal method	Compliance Option A	B	C
Coal washing removal, percent	27	20	8
Pulverizer, fly ash, and bottom ash reduction, percent	10	4	0
FGD system removal, percent	85	87	89
Overall SO_2 reduction in potential emissions	90	90	90

Table 6 illustrates that even if the FGD system attained only 85 percent reduction as UARG has claimed, the 90 percent removal standard would be achieved (Option A) even if a coal washing plant attained only 27 percent reduction in sulfur (the average reduction reported by the National Coal Association for conventional coal washing plants, OAQPS–78–1, IV–D–761). In addition, Table 6 illustrates that less fuel credit is needed when the FGD system attains more than 85 percent reduction (Options B and C). For example, even if the minimum amount of coal washing curently being achieved (20 percent in Ohio) is attained, only 87 percent FGD reduction would be needed. Thus, less than average or only average sulfur reduction credits (i.e., only 8–27% coal washing and 0–10% pulverizer, bottom ash and fly ash credits) would be needed to comply with the 90 percent reduction standard even if the FGD system *alone* only attained 85 to 89 percent control. Moreover, for 75 percent of the nation's coal reserves which have potential emissions less than 260 ng/J (6.0 lbs/million Btu) heat input (OAQPS–78–1, IV–E–12, page 18), less than 90 percent reduction in potential SO_2 emissions would be needed to meet the standard.

The statistical analysis submitted by UARG does not address the basis (FGD and sulfur reduction credits) of the standard and therefore does not alter the conclusions regarding the achievability of the promulgated percent reduction standard. The prescribed level can be achieved at the individual plant level even under the most demanding conditions through the application of scrubbers together with sulfur reduction credits.

Finally, UARG's petition (p. 15) states that the final standard was biased by an error in the preamble (see table, 44 FR 33592) which incorrectly referred to certain FGD removal efficiencies as "averages" rather than as geometric "means" (medians). These removal efficiencies were properly referred to as "means" in the EPA test reports. This discrepancy had no bearing on EPA's decision to promulgate a 90 percent SO_2 standard. Even though UARG claims a bias was introduced, their consultant's report states (see Appendix B, Page 46):

> Therefore, even though EPA mistakenly used the term "average SO_2 removal" in the promulgation, it is obvious that when the phrase "mean FGD efficiency" is used, EPA is correctly referred to the *mean* (or median) of the long-normal distribution of (1-eff).

Thus, even though Entropy (UARG's consultant which prepared their statistical analysis in Appendix B) "discovered a discrepancy" as UARG alleges, they did not reach a conclusion as UARG has done, that a simple transcription error in preparation of the preamble undermined the credibility of EPA's analysis of the test data. In fact, the analysis of test data performed by EPA (OAQPS–78–1, II–B–4) used correct statistical terminology.

The Sierra Club also submitted a petition that questioned the promulgated 90 percent, 30-day rolling average standard. The petition asks "why the final percentage of removal for 'full scrubbing' was set at only 90 percent for a 30-day average" in view of the preamble to the proposal which mentions a 92 percent reduction (43 FR 42159). The petition states that "EPA indicated that 85 percent scrubbing on a 24-hour average was equivalent to 92 percent on a 30-day average." This statement is a misquotation. The preamble actually stated that "an FGD system that could achieve a 92 percent long-term (30 days or more) mean SO_2 removal would comply with the proposed 85 percent (24-hour average) requirement." The long-term mean referred to is the median value (geometric mean) of FGD system performance, not an equivalent standard. Reference in the preamble was made to the background information supplement (OAQPS–78–1, III–B–4) which provided "a more detailed discussion of these findings." The 92 percent removal is described therein as the median (geometric mean) of the statistical distribution defined by the "line of improved performance" in Figure 4–1. A median is the middle number in a given sequence of numbers. Thus for a sequence of 24-hour or 30-day rolling average efficiencies, the median SO_2 removal (92 percent) is a level at which one-half of the 30-day rolling average FGD system efficiencies would be higher and one-half would be lower. Since one-half of the expected removal efficiencies would be lower than the 92 percent median, a standard could not be set at that level. The standard must recognize the range of 30-day rolling average FGD efficiencies that would be expected. The petition is based upon a misconception as to the meaning of the 92 percent value (a median) and is therefore not new information of central relevance to this issue.

The Environmental Defense Fund requested that EPA consider the relevance of the lime/limestone-adipic acid tests at Shawnee to this rulemaking. Adipic acid has been found to increase FGD system performance by limiting the drop in pH that normally occurs at the gas/liquid interface during SO_2 absorption. Test runs at Shawnee

showed increased FGD performance (in one test series the efficiency increased from 71 percent to 93 percent) with no apparent adverse impact upon FGD system operation.

EPA agrees that use of adipic acid additive in lime/limestone scrubbing solutions appears very promising and is currently planning a full-scale FGD system demonstration. Several important areas are to be evaluated in the EPA test program. The handling and disposal characteristics of waste sludges from the scrubber must be evaluated to see that adipic acid does not affect control of leachates into groundwater. In addition, the consumption rate of adipic acid by the FGD system and its ultimate disposition must be evaluated. Furthermore, tests must be conducted to show whether or not the concentration of adipic acid in FGD system sludge poses significant environmental problems. In the absence of such data, EPA does not believe it prudent to include adipic acid as a basis for the current revised standard.

IV. Particulate Matter Standards

Only one of the four petitions for reconsideration raised issues concerning the particulate matter standard. In their petition, the Utility Air Regulatory Group (UARG) argued principally that baghouse technology was not demonstrated on large coal-fired utility boilers and that the 13 ng/J (0.03 lb/million Btu) heat input standard could not be achieved at reasonable costs with electrostatic precipitators on low-sulfur coal applications. They also noted that emission test data on a 350 MW baghouse application was placed in the record after the close of the comment period. In response to these data, UARG presented operating information on baghouse systems obtained from two coal-fired installations. In addition they restated arguments that had been raised in their January 1979 comments concerning EPA's data base and the potential effects of NO_x and SO_2 emission control on particulate emissions.

In reaching his decision that baghouse technology is adequately demonstrated, the Administrator took into account a number of factors. In addition to the emission test data and other technical information contained in the record, he placed significant weight on the fact that at least 26 baghouse-equipped coal-fired electric utility steam generators were operating prior to promulgation of the standard and that 28 additional units were planned to start operation by the end of 1982. He also noted that some of the utility companies operating baghouses on coal-fired steam generators were ordering more baghouses and that none of them had announced plans to decommission or retrofit a baghouse controlled plant because of operating or cost problems. The Administrator believed that this was a strong indication that some segments of the utility industry believe that baghouses are practical, economical, and adequately demonstrated systems for control of particulate emissions. These electric utility baghouses are being applied to a wide range of sizes of steam generators and to coals of varying rank and sulfur content. The Industrial Gas Cleaning Institute speaking for the manufacturers of baghouses submitted comments (OAQPS–78–1, IV–D–247) confirming that baghouses are adequately demonstrated systems for control of particulate emissions from coal-fired steam-electric generators of all sizes and types.

In the proposal, EPA acknowledged that large baghouses of the size that would typically be used to meet the standard had only been recently activated. Further, the Agency announced that it planned to test a 350 MW unit (43 FR 42169, center column). The validated test data from this unit, located at the Harrington Station, demonstrated that the standard could be achieved at large facilities (OAQPS–78–1, V–B–1, page 4–1). The Agency also became aware that the operators of the facility were encountering start-up problems. After carefully evaluating the situation, the Agency concluded that the problems were temporary in nature (44 FR 33585, left column).

Furthermore, Appendix E of the UARG petition supports the Agency finding. According to Appendix E, the start-up problems experienced at Harrington Station (Unit #2) have not affected unit availability nor have they altered the utility's plans for equipping another large coal-fired steam generator at the site (Unit #3) with a baghouse. Appendix E noted, "The company feels that the baghouse achieved an availability equal to that of the electrostatic precipitator installed in unit 1" (UARG petition, Appendix E, page 2). The Appendix also examined two retrofit baghouse installations on boilers firing Texas lignite at the Monticello Station (Unit #1 and Unit #2). While the first unit that came on line experienced problems, Appendix E notes, "Since the start-up of Unit 2 bag filter, the baghouse has been operational at all times the boiler was on line (due to the solution of the majority of the problems associated with Unit 1 baghouse)" (UARG petition, Appendix E, page 5). These findings served to reinforce the Agency's conclusion that problems encountered at these initial installations are correctible.

Based on the Harrington and Monticello experience, UARG maintained that EPA did not properly consider the cost of activating and maintaining a baghouse. Contrary to UARG's position, the cost estimates developed by EPA provide liberal allowances for start-up and continued maintenance. For example, the Agency's cost estimates for a baghouse for a 350 MW power plant provided over $1.4 million for start-up and first year maintenance of which $440,000 was included for bag replacement (OAQPS–78–1, II–A–64 and VI–B–12). For subsequent years, $710,000 per year was allowed for routine maintenance of which $440,000 was included for bag replacement. In comparison, the UARG petition indicated that bag replacement costs during the first year of operation of the baghouse at the Harrington Station (350 MW capacity) would be $250,000 and the bag replacement costs at the two Monticello baghouse units (610 MW capacity total) would total about $642,000. From the information provided by UARG, it appears that the Agency has fully accounted for any potential costs that may be incurred during start-up or annual maintenance.

UARG further maintained that higher pressure drops encountered at these initial installations would increase the cost of power to operate a baghouse beyond those estimated by the Agency. The Administrator agrees that if higher pressure drops are encountered an increase in cost will be incurred. However, even assuming that the pressure drops initially experienced at the Harrington and Monticello Stations occur generally, the annual cost will not increase sufficiently to affect the Administrator's decision that the standard can be achieved at a reasonable cost. For example, the increase in pressure drop reported by UARG (UARG petition, page 43) at the Harrington station would result in a cost penalty of about $191,000 per year, which represents only a 4.5 percent increase in the total annualized baghouse costs projected by EPA (OAQPS–78–1, II–A–64, page 3–18) and

less than one percent increase in relation to utility operating costs. It should be reported, however, that as a result of corrective measures taken at Harrington station since start-up, the operating pressure drop reported by UARG has been reduced. If the pressure drop stabilizes at this improved level 2 kilopascals (8 inches H_2O) rather than the 2.75 kilopascals (11 inches H_2O) suggested by UARG the $191,000 cost penalty would be reduced by some $90,000 per year (OAQPS–78–1, VI–B–11 and UARG petition, page 43).

UARG also maintained that a period longer than 180 days after start-up is required to shake down new baghouse installations, and that EPA should amend 40 CFR 60.8, which requires compliance to be demonstrated within 180 days of start-up. UARG based these comments on the experience at the Harrington and Monticello Stations. It is important to understand that 40 CFR 60.8 only requires compliance with the emission standards within 180 days of start-up and does not require, or even suggest, that the operation of the facility be optimized within that time period. Optimization of a system is a continual process based on experience gained with time. On the other hand, a system may be fully capable of compliance with the standard before it is fully optimized.

In the case of the Harrington station the initial performance test was conducted by the utility during October 1978 (which was within four months of start-up). The initial test and a subsequent one were found however, to be invalid due to testing errors and therefore it was February 1979 before valid test results were obtained for the Harrington Unit (OAQPS–78–1, IV–B–1, page 42). This test clearly demonstrated achievement of the 13 ng/J (0.03 lb/million Btu) heat input emission level. These results were obtained even though the unit was still undergoing operation and maintenance refinements. With respect to the Monticello station, UARG reported that no actual performance test data are available (UARG petition, Appendix E, page 6).

UARG also maintained that baghouses are not suitable for peaking units because of the high energy penalty associated with keeping the baghouse above the dew point. EPA recognizes that baghouses may not be the best control device for all applications. In those instances where high energy penalties may be incurred in heating the baghouse above the dew point, the utility would have the option of employing an electrostatic precipitator. However, some utilities will be using baghouses for peaking units. For example, the baghouse control system on four subbituminous, pulverized coal-fired boilers at the Kramer Station have been equipped with baghouse preheat systems and that station will be placed in peaking service in the near future (OAQPS–78–1, VI–B–10).

UARG also argued that it may be necessary to install a by-pass system in conjunction with a baghouse to protect the baghouse from damage during certain operation modes. The use of such a system during periods of start-up, shutdown, or malfunction is allowed by the standard when in keeping with good operating practice.

The UARG petition implied that the test data base for electrostatic precipitator systems (ESP) is inadequate for determining that such systems can meet the standard. Contrary to UARG's position, the EPA data base for the standard included test data obtained under worst-case conditions, such as (1) when high resistivity ash was being collected, (2) during sootblowing, and (3) when no additives to enhance ESP performance were used (OAQPS–78–1, III–B–1, page 4–11 and 4–12). Even when all of the foregoing worst-case conditions were incurred simultaneously, particulate matter emission levels were still less than the standard. It should also be understood that none of the ESP systems tested were larger than the model sizes used for estimating the cost of control under worst-case conditions.

The UARG petition also questioned the Administrator's reasoning in failing to evaluate the economic impact of applying a 197 square meter per actual cubic meter per second (1000 ft ^{2}/1000 ACFM) cold-side ESP to achieve the standard under adverse conditions such as when firing low-sulfur coal. The Administrator did not evaluate the economic impact of applying a large, cold-side ESP because a smaller, less costly 128 square meter per actual cubic meter per second (650 ft ^{2}/1000 ACFM) hot-side ESP would typically be used. The Administrator believed that it would have been non-productive to investigate the economics of a cold-side ESP when a hot-side ESP would achieve the same level of emission control at a lower cost.

The UARG petition also suggested that hot-side ESP's are not always the best choice for low-sulfur coal applications. The Administrator agrees with this position. In some case, low-sulfur coals produce an ash which is relatively easy to collect since flyash resistivity is not a problem. Under such conditions it would be less costly to apply a cold-side ESP and therefore it would be the preferred approach. However, when developing cost impacts of the standard, the Agency focused on typical low-sulfur coal applications which represents worst case conditions, and therefore assessed only hot-side precipitators.

The UARG petition suggests that in some cases the addition of chemical additives to the flue gas may be required to achieve the standard with ESPs, and the Agency should have fully assessed the environmental impact of using such additives. The Administrator, after assessing all available data, concluded that the use of additives to improve ESP performance would not be necessary (OAQPS–78–1, III–B–1, page 4–11). Therefore, it was not incumbent upon EPA to account for the environmental impact of the use of additives other than to note that such additives could increase SO_3 or acid mist emissions. In instances where a utility elects to employ additives as a cost saving measure, their potential effect on the environment can be assessed on a case-by-case basis during the new source review process.

UARG also maintained that there are special problems with some low-sulfur coals that would preclude the use of hot-side ESPs and attached Appendix F in support of their position. Review of Appendix F reveals that while the author discussed certain problems related to the application of hot-side ESPs on some western low-sulfur coal, he also set forth effective techniques for resolving these problems. The author concluded, "The evidence of more than 11 years of experience indicates that hot precipitators are here to stay and very likely their use on all types of coal will increase."

UARG also argued that the data base in support of the final particulate standard for oil-fired steam generating units was inadequate. The standard is based on a number of studies of particulate matter control for oil-fired boilers. These studies were summarized and referenced in the BID for the proposed standard (OAQPS–78–1, III–B–1, page 4–39). These earlier studies (*Control of Particulate Matter from Oil Burners and Boilers*, April 1976, EPA–450/3–76–005; and *Particulate Emission Control Systems for Oil-fired Boilers*, December 1974, EPA–450/3–74–063) support the conclusion that ESP control systems are applicable to oil-fired steam generators and that such emission control systems can achieve the standard. The achievability of the standard was also confirmed by the Hawaiian Electric Company, a firm that would be significantly affected by the standard since virtually all their new

generating capacity will be oil-fired due to their location. In their comments the company indicated, "Hawaiian Electric Company supports the standards as proposed in so far as they impact upon the electric utilities in Hawaii" (OAQPS–78–1, IV–D–159).

UARG also argued that the Administrator had little or no data upon which to base a conclusion that the particulate standard is achievable for lignite-fired units. In making this assertion, UARG failed to recognize that the Agency had extensively analyzed lignite-fired units in 1976 and concluded that they could employ the same types of control systems as those used for other coal types (EPA–450/2–76–030a, page II–29). Additionally, review of the literature and other sources revealed no new data that would alter this finding (Some of the data considered includes OAQPS–78–1, II–I–59, II–I–312, and II–I–322) and the Agency continues to believe that the emission standards are achievable when firing all types of coal including lignite coal. UARG has not provided any information during the comment period or in their petition which would suggest any unique problems associated with the control of particulate matter from lignite-fired units.

The UARG petition alleged that the Administrator did not take into account the effect of NO_x control in conjunction with promulgation of the particulate standard. In developing the NO_x standard, the Administrator assessed the possibility that NO_x controls may increase ash combustibles and thereby affect the mass and characteristics of particulate emissions. The Administrator concluded, however, that the NO_x standard can be achieved without any increase in ash combustibles or any significant change in ash characteristics and therefore there would be no impact on the particulate standard (OAQPS–78–1, III–B–2, page 6–14).

UARG also raised the issue of sulfate carryover from the scrubber slurry and its potential effect on particulate emissions. EPA initially addressed this issue at proposal and concluded that with proper mist eliminator design and maintenance, liquid entrainment can be controlled to an acceptable level (43 FR 42170, left column). Since that time, no new information has been presented that would lead the Administrator to reconsider that finding.

In summary, UARG failed to present any new information on particulate matter control that is centrally relevant to the outcome of the rule.

V. NO_x Standards

The Utility Air Regulatory Group (UARG) sought reconsideration of the NO_x standards. They maintained that the record did not support EPA's findings that the final standards could be achieved by all boiler types, on a variety of coals, and on a continuous basis without an unreasonable risk of adverse side effects. In support of this position, they argued that while EPA's short-term emissions data provided insight into NO_x levels attainable by utility boilers under specified conditions during short-term periods, they did not sufficiently support EPA's standards based on continuous compliance. Further, they maintained that the continuous monitoring data relied on by the Agency does not support the general conclusions that all boiler types can meet the standards on a variety of coals under all operating conditions. They also argued that the Agency failed to collect or adequately analyze data on the adverse side effects of low-NO_x operations. Finally, they contended that vendor guarantees have been shown not to support the revised standards. The arguments presented in the petition were discussed in detail in an accompanying report prepared by UARG's consultant.

In general, the UARG petition merely reiterated comments submitted in January 1979. Their arguments concerning short-term test data, the potential adverse side effects of low-NO_x operation, and manufacturer's guarantees did not reflect new information nor were they substantially different from those presented earlier. For example, in their petition, UARG asserted that new information received at the close of comment period revealed that certain data EPA relied upon to conclude that low-NO_x operations do not increase the emissions of polycyclic organic matter (POM) are of questionable validity (UARG petition, page 56). This comment repeats the position stated in UARG's January 15, 1979, submittal (OAQPS 78–1, IV–D–611, attachment—KVB report, January 1979, page 86). More importantly, UARG failed to recognize that EPA did not rely on the tests in question and that the Agency noted in the BID for the proposed standards (OAQPS–78–1, III–B–2, page 6–12) that the data were insufficient to draw any conclusion on the effects of modern, low-NO_x Babcock and Wilcox burners on POM emissions. Instead, EPA based its conclusions in regard to POM on its finding that combustion efficiency would not decrease during low-NO_x operation and therefore, there would not be an increase in POM emissions (43 FR 42171, left column and OAQPS–78–1, III–B–2, page 9–6).

Similarly, UARG did not present any new data in regard to boiler tube corrosion. They merely restated the arguments they had raised in their January 1979 comments which questioned EPA's reliance on corrosion test samples (coupons). EPA believes that proper consideration has been given to the corrosion issues and substantial data exist to support the Administrator's finding that the final requirements are achievable without any significant adverse side effect (44 FR 33602, left column). In addition, UARG also maintained that the Agency should explain why it dismissed the 190 ng/J (0.45 lb/million Btu) heat input NO_x emission limit (44 FR 33602, right column) applicable to power plants in New Mexico. In dismissing the recommendation that the Agency adopt a 190 ng/J emission limit, the Administrator noted that the only support for such an emission limitation was in the form of vendor guarantees.

In relation to vendor guarantees, UARG maintained in their January comments and reiterate in their petition that EPA should not rely on vendor guarantees as support for the revised standards. EPA cannot subscribe to UARG's narrow position. While vendor guarantees alone would not provide a sufficient basis for a new source performance standard, EPA believes that consideration of vendor guarantees when supported by other findings is appropriate. In this instance, the vendor guarantees served to confirm EPA findings that the boiler manufacturers possess the requisite technology to achieve the final emission limitations. This approach was described by Foster Wheeler in their January 3, 1979, letter to UARG, (OAQPS 78–1, IV–D–611, attachment—KVB report, January 1979, page 119) that states, "When a government regulation, which has a major effect on steam generator design, is changed it is unreasonable to judge the capability of a manufacturer to meet the new regulation by evaluating equipment designed for the older less stringent regulation."

This observation is also germane to the arguments raised by UARG with respect to EPA data on short-term emission tests and continuous monitoring. In essence, UARG maintained that the EPA data base was inadequate because boilers designed and operated to meet the old 300 ng/J (0.7 lb/million Btu) heat input limitation under Subpart D have not been shown to be in continuous compliance with the

new standard under Subpart Da. While this statement is true, these units, which were designed and operated to meet the old standard, incurred only five exceedances of the new standards on a monthly basis. Moreover, a review of the available 34 months of continuous monitoring data from six utility boilers revealed that they all operated well below the applicable standard (OAQPS-78-1, V-B-1).

In addition, UARG argued that the available continuous monitoring data demonstrated that the Agency should not have relied on short-term test data. Citing Colstrip Units 1 and 2, they noted that less than one-third of the 30-day average emissions fell below the units' performance test levels of 125 ng/J (0.29 lb/million Btu) heat input and 165 ng/J (0.38 lb/million Btu) heat input, respectively. They further maintained that this had not been considered by the Agency. In fact, the Administrator recognized at the time of promulgation that emission values obtained on short-term tests could not be achieved continuously because of potential adverse side effects and therefore established emission limits well above the values measured by such tests (44 FR 42171, left column). In addition, EPA took into account the emission variability reflected by the available continuous monitoring data when it established a 30-day rolling average as the basis of determining compliance in the standards (44 FR 33586, left column).

UARG also maintained in their petition that EPA should not rely on the Colstrip continuous monitoring data because it was obtained with uncertified monitors. The Administrator recognized that the Colstrip data should not be relied on in absolute terms since monitors were probably biased high by approximately 10 percent (OAQPS 78-1, III-B-2, page 5-7). EPA's analysis of data revealed, however, that it would be appropriate to use the data to draw conclusions about variability in emissions since the shortcoming of the Colstrip monitors did not bias such findings. This data together with data obtained using certified continuous monitors at five other facilities (OAQPS 78-1, V-B-1, page 5-3) and the results from 30-day test programs (manual tests performed about twice per day) at three additional plants (OAQPS 78-1, II-B-62 and II-B-70) enabled the Administrator to conclude that emission variability under low-NO_x operating conditions was small and therefore the prescribed emission levels are achievable on a continuous basis.

UARG argued that since the only continuous monitoring data available was obtained from boilers manufactured by Combustion Engineering and on a limited number of coal types, the Agency did not have a sufficient basis for finding that the standards can be achieved by other manufacturers or when other types of coals are burned. The Administrator concluded after reviewing all available information that the other three major boiler manufacturers can achieve the same level of emission reduction as Combustion Engineering with a similar degree of emission variability (43 FR 42171, left column and 44 FR 33586, middle column). This finding was confirmed by statements submitted to UARG and EPA by the other vendors that their designs could achieve the final standards, although they expressed some concern about tube wastage potential (OAQPS-78-1, III-D-611, attachment-KVB report, pages 116-121 and IV-D-30). EPA has considered tube wastage (corrosion) throughout the rulemaking and has determined that it will not be a problem at the NO_x emission levels required by the standards (44 FR 33602, left column). With respect to different coal types, the Agency concluded from its analysis of available data that NO_x emissions are relatively insensitive to differing coal characteristics and therefore other coal types will not pose a compliance problem (43 FR 42171, left column and OAQPS-78-1, IV-B-24). UARG did not submit any data to refute this finding.

UARG also argued that the continuous monitoring data should have been accompanied by data on boiler operating conditions. EPA noted that the data were collected during extended periods representative of normal operations and therefore it reflected all operational transients that occurred. In particular, at Colstrip units 1 and 2 more than one full year of continuous monitoring data was analyzed for each unit. In view of this, EPA believes that the data base accurately reflects the degree of emission variability likely to be encountered under normal operating conditions. UARG recognized this in principle in their January 15 comments (Part 4, page 15) when they stated that "continuous monitors would measure all variations in NO_x emissions due to operational transients, coal variability, pollution control equipment degradation, etc."

In their petition, UARG restated their January 1979 comments that EPA's short-term test data were not representative and therefore should not serve as a basis for the standard. As noted earlier, EPA did not rely exclusively on short-term test data in setting the final regulations. In addition, contrary to the UARG claim, EPA believes that the boiler test configurations used to achieve low-NO_x operations reflect sound engineering judgement and that the techniques employed are applicable to modern boilers. This is not to say that the boiler manufacturers may not choose other approaches such as low-NO_x burners to achieve the standards. While recognizing that EPA's test program was concentrated on boilers from one manufacturer, sufficient data was obtained on the other major manufacturers' boilers to confirm the Agency's finding that they would exhibit similar emission characteristics (44 FR 33586, left column). Therefore, in the absence of new information, the Administrator has no basis to reconsider his finding that the prescribed emission limitations are achievable on modern boilers produced by all four major manufacturers.

VI. Emission Measurement and Compliance Determination

The Utility Air Regulatory Group (UARG) raised several issues pertaining to the accuracy and reliability of continuous monitors used to determine compliance with the SO_2 and NO_x standards. UARG particularly commented on the data from the Conesville Station. In addition, they also maintained that the sampling method for particulates was flawed. With respect to compliance determinations, UARG maintained that the method for calculating the 30-day rolling averages should be changed so that emissions before boiler outages are not included since they might bias the results. In addition, UARG argued that the standards were flawed since EPA had not included a statement as to how the Agency would consider monitoring accuracy in relation to compliance determination. With the exception of the method of calculating the 30-day rolling average and the comments on the Conesville station, the petition merely reiterated comments submitted prior to the close of the public comment period.

As to the reliability and durability of continuous monitors, information in the docket (OAQPS-78-1, II-A-88, IV-A-20, IV-A-21, and IV-A-22) demonstrates that on-site continuous monitoring systems (CMS) are capable and have operated on a long-term basis producing data which meet or exceed the minimum data requirements of the standards.

In reference to the Conesville project, UARG questioned why EPA dismissed the continuous monitoring results since it was the only long-term monitoring effort by EPA to gain instrument

operating experience. UARG maintained that this study showed monitor degradation over time and that it was representative of state-of-the-art monitoring system performance. This conclusion is erroneous. EPA does not consider the Conesville project adequate for drawing conclusions about monitor reliability because of problems which occurred during the project.

To begin with, UARG is incorrect in suggesting that the goal of the project was to obtain instrument operating experience. The primary purpose of the project was to obtain 90 days of continuous monitoring data on FGD system performance. Because of intermittent operation of the steam generator and the FGD system, this objective could not be achieved. As the end of the 90-day period approached, a decision was made to extend the test duration from three to six months. The intermittent system operation continued. As a result, when the FGD outages were deleted from the total project time of six months, the actual test duration was similar to those at the Louisville, Pittsburgh, and Chicago tests and did not, therefore, represent an extended test program.

EPA does not consider the Conesville results to be representative of state-of-the-art monitoring system performance. Because of the intermittent operation throughout the test period (OAQPS–78–1, IV–A–19, page 2), it became obvious that the goals of the program could not be met. As a result, monitoring system maintenance lapsed somewhat. For example, an ineffective sample conditioning system caused differences in monitor and reference method results (OAQPS–78–1, IV–A–20, page 3–2). If the EPA contractor had performed more rigorous quality assurance procedures, such as a repetition of the relative accuracy tests after monitor maintenance more useful results of the monitor's performance would have been obtained. Thus, the Conesville study re-emphasized the need for periodic comparisons of monitor and reference method data and the inherent value of sound quality assurance procedures.

The UARG petition suggested that the standards incorporate a statement as to how EPA will consider monitoring system accuracy during compliance determination. More specifically, UARG recommended that EPA define an error band for continuous monitoring data and explicitly state that the Agency will take no enforcement action if the data fall within the range of the error band. The Agency believes that such a provision is inappropriate. Throughout this rulemaking, EPA recognized the need for continuous monitoring systems to provide accurate and reproducible data. EPA also recognized that the accuracy of a CMS is affected by basic design principals of the CMS and by operating and maintenance procedures. For these reasons, the standards require that the monitors meet (1) published performance specifications (40 CFR Part 60 Appendix B) and (2) a rigorous quality assurance program after they are installed at a source. The performance specifications contain a relative accuracy criterion which establishes an acceptable combined limit for accuracy and reproducibility for the monitoring system. Following the performance test of the CMS, the standards specify quality assurance requirements with respect to daily calibrations of the instruments. As was noted in the rulemaking (44 FR 33611, right column), EPA has initiated laboratory and field studies to further refine the performance requirements for continuous monitors to include periodic demonstration of accuracy and reproducibility. In view of the existing performance requirements and EPA's program to further develop quality assurance procedures, the Administrator believes that the issue of continuous monitoring system accuracy was appropriately addressed. In doing so, he recognized that any questions of accuracy which may persist will have to be assessed on a case-by-case basis.

The UARG petition also raised as an issue the calculation of the 30-day rolling average emission rate. UARG maintained that the use of emission data collected before a boiler outage may not be representative of the control system performance after the boiler resumes operation. UARG indicated that boiler outage could last from a few days to several weeks and suggested that if an outage extends for more than 15 days, a new compliance period should be initiated. UARG also suggested that if a boiler outage is less than 15 days duration and the performance of the emission control system is significantly improved following boiler start-up, a new compliance period should be initiated. UARG argued that the data following start-up would be more descriptive of the current system performance and hence would provide a better basis for enforcement.

A basic premise of this rulemaking was that the standard should encourage not only installation of best control systems but also effective operating and maintenance procedures (44 FR 33595 center column, 33601 right column, and 33597 right column). The 30-day rolling average facilitates this objective. In selecting this approach, the Agency recognized that a 30-day average better reflects the engineering realities of SO_2 and NO_x control systems since it affords operators time to identify and respond to problems that affect control system efficiency. Daily enforcement (rolling average) was specified in order to encourage effective operating and maintenance procedures. Under this approach, any improvement in emission control system performance following start-up will be reflected in the compliance calculation along with efficiency degradations occurring before the outage. Therefore, the 30-day rolling average provides an accurate picture of overall control system performance.

On the other hand, the UARG suggestion would provide a distorted description of system performance since it would discount certain episodes of poor control system performance. That is, the system operator could allow the control system to degrade and then shut-down the boiler before a violation of the standard occurred. After start-up and any required maintenance, a new compliance period would commence, thereby excusing any excursions prior to a shut-down. In addition, since a new averaging period would be initiated the Agency would be unable to enforce the standard for the first 29 boiler operating days after the boiler had resumed operation. In the face of this potential for circumvention of the standards, the Administrator rejects the UARG approach.

UARG also reiterated their previous comments that EPA did not properly consider the accuracy and precision of Reference Method 5 for measuring particulate concentrations at or below 13 ng/J (0.03 lb/million Btu) heat input. EPA has recognized throughout this rulemaking that obtaining accurate and precise measurements of very low concentrations of particulate matter is difficult. In view of this, detailed and exacting procedures for the clean-up and analyses of the sample probe, filter holder, and the filter were specified in Method 5 to assure accuracy in determining the mass collected. Additionally, EPA has required that the sampling time be increased from 60 minutes to 120 minutes. This will increase the total sample volume from a minimum of 30 dscf to 60 dscf, thus increasing the total mass collected to about 100 mg at a loading of 13 ng/J (0.03 lb/million Btu) heat input. EPA has concluded that measurement of mass at this level can be reproduced within ±10 percent.

UARG also maintained that less than ideal sampling can cause particulate emission measurements to be inaccurate

and this has not been evaluated. EPA has addressed the question of determining representative locations and the number of sampling points in some detail in the reference methods and appropriate subparts. These procedures were designed to assure accurate measurements. EPA has also evaluated the effects of less than ideal sampling locations and concluded that generally the results would be biased below actual emissions. Assessment of the extent of possible biases in measurement data, however, must be made on a case-by-case basis.

UARG raised again the issue of acid mist generated by the FGD system being collected in the Reference Method 5 sample, therefore rendering the emission limit unachievable. EPA has recognized this problem throughout the rulemaking. In response to the Agency's own findings and the public comments, the standards permit determination of particulate emissions upstream of the scrubber. In addition, EPA announced that it is studying the effect of acid mist on particulate collection and is developing procedures to correct the collected mass for the acid mist portion.

VII. Applicability of Standards

Sierra Pacific Power Company and Idaho Power Company (collectively, "Sierra Pacific") petitioned the Administrator to reconsider the definition of "affected facility," asking that the applicability date of the standards be established as the date of promulgation rather than the date of proposal. 40 CFR 60.40a provides:

> (a) The affected facility to which this subpart applies is each electric utility steam generating unit:
> * * *
> (2) For which construction or modification is commenced after September 18, 1978.

September 19, 1978, is the date on which the proposed standard was published in the **Federal Register**. EPA based this definition on sections 111(a)(2) and 111(b)(6) of the Act. Section 111(a)(2) provides:

> The term "new source" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

Section 111(b)(6) includes a similar provision specifically drafted to govern the applicability date of revised standards for fossil-fuel burning sources (of which this standard is the chief example.) It provides:

> Any new or modified fossil fuel-fired stationary source which commences construction prior to the date of publication of the proposed revised standards shall not be required to comply with such revised standards.

Sierra Pacific does not dispute that the Agency's definition of affected facility complies with the literal terms of sections 111(a)(2) and 111(b)(6). Sierra Pacific maintains, however, that the definition is unlawful, because the standard was promulgated more than 6 months after the proposal, in violation of sections 111(b)(1)(B) and 307(d)(10). Section 111(b)(1)(B) provides that a standard is to be promulgated within 90 days of its proposal. Section 307(d)(10) allows the Administrator to extend promulgation deadlines, such as the 90-day deadline in section 111(b)(1)(B), to up to 6 months after proposal. Sierra Pacific argues that section 111(a)(2) does not apply unless the deadlines in sections 111(b)(1)(B) and 307(d)(10) are met. In this case the final standard was promulgated on June 11, 1979, somewhat less than 9 months after proposal. (It was announced by the Administrator at a press conference on May 25, 1979, and signed by him on June 1, 1979.)

In the Administrator's view, the applicability date is properly the date of proposal. First, the plain language of section 111(a)(2) provides that the applicability date is the date of proposal. Second, the legislative history of section 111 shows that Congress did not intend that the applicability date should be the date of proposal only where a standard was promulgated within 90 days of proposal. Section 111(a)(2) took its present form in the conference committee bill that became the 1970 Clean Air Act Amendments, whereas the 90-day requirement came from the Senate bill, and there is no indication that Congress intended to link these two provisions.[2]

Moreover, this interpretation represents longstanding Agency practice. Even where responding to public comments delays promulgation more than 90 days, or more than 6 months, after proposal, the applicability dates of new source performance standards are established as the date of proposal. See 40 CFR Part 60, Subparts D *et seq.*

Sierra Pacific argues that its position has been adopted by EPA in "analogous" circumstances under the Clean Water Act. This is inaccurate. Section 306 of the Clean Water Act specifically provides that the date of proposal of a new source standard is the applicability date only if the standard is promulgated within 120 days of proposal (section 306(a)(2), (b)(1)(B)).

Sierra Pacific suggests that utilities are "unfairly prejudiced" by the applicability date, but does not submit any information to support this claim. In any event, there does not seem to be any substantial unfair prejudice. At the time of proposal, the Administrator had not decided whether a full or partial control alternative should be adopted in the final SO_2 standard. As a result, the Administrator proposed the full control alternative stating (43 FR 42154, center column):

> * * * the Clean Air Act provides that new source performance standards apply from the date they are proposed and it would be easier for power plants that start construction during the proposal period to scale down to partial control than to scale up to full control should the final standard differ from the proposal.

In fact, the final SO_2 standard was less stringent than the proposed rule.

In this case, utilities were on notice on September 19, 1978, of the proposed form of the standard, and that the standard would apply to facilities constructed after that date. In March 1979, it became clear to the Agency that it would not be possible to respond to all the public comments and promulgate the final standards by March 19, as required by the consent decree in *Sierra Club* v. *Costle*, a suit brought to compel promulgation of the standard. (The comment period had only closed on January 15; EPA had received over 625 comment letters, totalling about 6,000 pages, and the record amounted to over 21,000 pages.) The Agency promptly contacted the other parties to *Sierra Club* v. *Costle*, and all the parties jointly filed a stipulation that the standand should be signed by June 1 and that the Administrator should not seek "any further extensions of time." This stipulation was well-publicized (see, for example, 9 Environment Reporter Current Developments 2246, March 30, 1979). Thus utilities such as Sierra Pacific had reasonable assurance that the standard would be signed by June 1, as it was.

Even assuming, as Sierra Pacific does, that section 111 required the standard to be promulgated by March 19, utilities had to wait only an additional period of 84 days to know the precise form of the promulgated standard. This delay is not substantial in light of the long lead times required to build a utility boiler, and in light of the fact that the pollution control techniques required to comply with the promulgated standard are substantially

[2] In any event, in the Administrator's view the 90-day requirement in section 111(b)(1)(B) no longer governs the promulgation or revision of new source standards. It has been replaced by procedures set forth in section 111(f) enacted by the 1977 amendments.

the same as those required by the proposed standard.

Sierra Pacific's proposal that the applicability date be shifted to the date of promulgation is also inconsistent with Congress' clear desire that the revised standard take effect promptly. See section 111(b)(6).

In conclusion, Sierra Pacific has submitted no new information, has not shown that it has been prejudiced in any way, and has simply presented an argument that is incorrect as a matter of law. Its objection is therefore not of central relevance and its petition is denied.

Dated: January 30, 1980.

Douglas M. Costle,

Administrator.

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